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federal register

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Highlights

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Highlights

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Rules and Regulations

Federal Register
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Friday, October 5, 1979

OFFICE OF PERSONNEL MANAGEMENT

5 CFR Parts 340 and 890

Part-Time Employment; Federal Employees Health Benefits Program

AGENCY: Office of Personnel Management.

ACTION: Final Regulations.

SUMMARY: The Office of Personnel Management (OPM) is issuing final regulations to implement its responsibilities under Pub. L. 95-437, the Federal Employees Part-time Career Employment Act of 1978. This law narrows the definition of part-time career employment in the Federal Government from scheduled work of less than 40 hours per week to scheduled work between 16 and 32 hours per week, requires most Federal agencies to develop and administer a program to expand part-time employment opportunities, and changes the personnel ceiling and fringe benefit provisions governing part-time career Federal employees. The regulations define coverage under the Act for employment (Part 340) and health insurance (Part 890) purposes, and outline OPM responsibilities to provide technical guidance and assistance in the part-time employment area. The regulations also implement the statutory requirement that agencies report their progress in expanding part-time employment opportunities to the Office of Personnel Management on a twice-yearly basis.

DATE: Effective Date October 5, 1979.

FOR FURTHER INFORMATION CONTACT:

Ed McHugh, 202-632-6817 (employment). Staffing Services, Room 6524.
Ed Borchers, 202-632-4684 (health benefits). Compensation, Room 4334. Office of Personnel Management, 1900 E Street, N.W., Washington, D.C. 20415.

SUPPLEMENTARY INFORMATION:

Background

On April 6, 1979, the Office of Personnel Management published interim regulations to implement the Federal Employees Part-time Career Employment Act of 1978 (5 U.S.C. 3401 et seq.) and invited comments from the public (44 FR 20697). Written comments were received from ten individuals and organizations.

As a result of comments and suggestions received during this period, the Office of Personnel Management has modified the final regulations as described below. The Office will also supplement the regulations with guidance issued through the Federal Personnel Manual System to clarify certain items addressed during the public comment period which are outside the scope of these regulations.

Statutory Provisions

Some comments were directed at the provisions of the Federal Employees Part-time Career Employment Act contained in Subpart A of the regulations. Although these provisions are by and large not subject to modification by OPM regulation, they will be monitored by OPM, and amendments to the statute may be recommended for congressional action in the future. The substance of these comments is, therefore, reflected below.

Several Federal agencies indicated that the limitation of new part-time employees to a 32-hour-per-week maximum regular work schedule is unduly restrictive to management as well as employees. Although the major thrust of Pub. L. 95-437 was to expand Federal part-time employment opportunities, Congress also evidenced clear intent to end the practice of employing "nominal" part-time employees in the 33- to 39-hour-per-week range to skirt personnel ceilings. Therefore, agencies may not regularly employ workers with permanent appointments who become part time on or after April 8, 1979, under schedules of more than 32 hours per week. This prohibition does not apply to the employment of part-timers who were already working on a permanent part-time basis before that date for as long as they continue to work part time. Also it does not restrict agencies from temporarily increasing an employee's hours of duty above 32 hours per week for limited periods to meet heavy workloads, permit employee training, etc. No specific limitation has been placed on these temporary increases; however, their use must be consistent with the congressional intent reflected above.

Another statutory provision which drew comments was the prorating of the Government contribution toward the health insurance of new part-time employees according to the percentage of a full-time schedule the employees work. Most respondents recognized that this provision is designed to make fringe benefit arrangements more equitable and reduce the cost to the Government of employing additional part-time workers. Several indicated, however, that the additional costs incurred by the employee for such benefits could serve as a deterrent to working part time.

As provided in Pub. L. 95-437, part-time employees working schedules of less than 16 hours per week are excluded from the requirement that the Government contribution toward the health insurance of part-time employees be prorated. Thus, while new part-time employees working from 16 to 32 hours per week receive only a portion of the Government contribution for health insurance, those working less than 16 hours per week receive the full amount. Several respondents noted this inconsistency. Alternatives to remedy this are under consideration.

Finally, one employee labor organization recommended including in the regulation the statutory provision prohibiting abolishment of occupied positions to make them available on a part-time basis, and the provision prohibiting a full-time employee from being required to accept part-time employment as a condition of continued employment. These provisions are incorporated in Subpart A of the regulations as part of the substantive language of Pub. L. 95-437.

Several Federal agencies indicated that the statutory requirement for special goals and timetables to expand part-time employment opportunities are burdensome. OPM instructions in the Federal Personnel Manual on part-time employment will encourage agencies to incorporate such goals and timetables, to the extent possible, in ongoing affirmative action programs.

Exception of Employees Working Less Than 16 Hours Per Week

The statutory part-time employment scheme established by Pub. L. 95–437 generally limits part-time employment to 16 to 32 hours per week. However, Congress did not explicitly evidence intent to end the practice of employing career part-timers for less than 16 hours per week in the same way that 33- to 39-hour-per-week employment was proscribed. Recognizing that there were circumstances in which agencies needed to employ permanent workers under regular schedules of less than 16 hours per week, OPM regulations provide for this type of employment as an exception to the general definition of part-time employment in the statute.

Respondents asked about the rationale for this exception as well as the statutory language which provides such employees with a larger Federal health insurance contribution than employees in the 16- to 32-hour week range. (See statutory provisions above).

Mixed Tour Employees

A few Federal agencies use career-seasonal employees who work under "mixed" tours of duty (i.e., varying periods of full-time, part-time and intermittent service) during the course of a year. One agency inquired whether seasonal employees serving on a part-time basis as part of their mixed tour are subject to the schedule limitations and health insurance proration provided for part-time employees by Pub. L. 95–437.

In OPM's view, the Federal Employees Part-time Career Employment Act of 1978 is designed to encourage regularly scheduled employment from 16 to 32 hours per week. Although many career-seasonal employees occasionally work on a part-time basis, we understand such service to be limited and incidental to a more extended period of full-time employment during the course of the year.

We, therefore, have determined that seasonal employees with mixed tours of duty are not covered by the Federal Employees Part-time Career Employment Act of 1978. Our final implementing regulations on Pub. L. 95–437 specifically exempt employees serving under permanent appointments who have mixed tours of duty from the provisions of this Act.

Recruitment of Part-Time Workers

Several responses suggested that OPM should take on the principal responsibility for recruiting part-time workers and communicating and advertising part-time job vacancies to the public as required under 5 U.S.C. 3402(a)(1)(E). It was also suggested that OPM establish a nationwide talent bank containing the names of potential part-time employees.

Because of these concerns OPM will look to the development of improved methods for filling part-time positions in carrying out the research and demonstration responsibilities required by 5 U.S.C. 3402(b)(2).

The Office of Personnel Management has examined and considered all the comments brought to its attention during the public comment period. In preparing the preceding summary, the Office has tried to address the major points raised in the letters it has received. Certain of the comments and suggestions, however, involved matters outside the scope of these regulations. Others addressed issues of program administration that will be covered in guidance materials the Office will issue to assist agencies in implementing the program.

Office of Personnel Management.

Beverly M. Jones,

Issuance System Manager.

Accordingly, the Office of Personnel Management is amending Title 5, Code of Federal Regulations, as follows:

(1) A new Part 340 is added as set forth below:

PART 340—PART-TIME EMPLOYMENT

Authority: 5 U.S.C. 3401 et seq.

Subpart A—Principal Statutory Requirements

§ 340.101 Principal statutory requirements.

This subpart incorporates for the benefit of the user of the principal statutory requirements governing part-time career employment, as contained in 5 U.S.C. 3401–3408, and related provisions of Pub. L. 95–437.

Short Title

Sec. 1. This Act may be cited as the "Federal Employees Part-Time Career Employment Act of 1978".

Congressional Findings and Purpose

Sec. 2. (a) The Congress finds that—

(1) many individuals in our society possess great productive potential which goes unused because they cannot meet the requirements of a standard workweek; and

(2) part-time permanent employment—

(A) provides older individuals with a gradual transition into retirement;

(B) provides employment opportunities to handicapped individuals or others who require a reduced workweek;

(C) provides parents opportunities to balance family responsibilities with the need for additional income;

(D) benefits students who must finance their own education or vocational training;

(E) benefits the Government, as an employer, by increasing productivity and job satisfaction, while lowering turnover rates and absenteeism, offering management more flexibility in meeting work requirements, and filling shortages in various occupations; and

(F) benefits society by offering a needed alternative for those individuals who require or prefer shorter hours (despite the reduced income), thus increasing jobs available to reduce unemployment while retaining the skills of individuals who have training and experience.

(b) The purpose of this Act is to provide increased part-time career employment opportunities throughout the Federal Government.

"§ 3401 Definitions

"For the purpose of this subchapter—

"(1) 'agency' means—

"(A) an Executive agency;

"(B) a military department;

"(C) an agency in the judicial branch;

"(D) the Library of Congress;

"(E) the Botanic Garden; and

"(F) the Office of the Architect of the Capitol; but does not include—

"(i) a Government controlled corporation;

"(ii) the Tennessee Valley Authority;

"(iii) the Alaska Railroad;

"(iv) the Virgin Island Corporation;

"(v) the Panama Canal Company;

"(vi) the Federal Bureau of Investigation, Department of Justice;

"(vii) the Central Intelligence Agency; and

"(viii) the National Security Agency, Department of Defense; and

"(2) 'part-time career employment' means part-time employment of 16 to 32 hours a week under a schedule consisting of an equal or varied number of hours per day, whether in a position which would be part-time without regard to this section or one established to allow job-sharing or comparable arrangements, but does not include employment on a temporary or intermittent basis.

"§ 3402. Establishment of part-time career employment programs.

"(a)(1) In order to promote part-time career employment opportunities in all grade levels, the head of each agency, by regulation, shall establish and maintain a program for part-time career employment within such agency. Such regulations shall provide for—

"(A) the review of positions which, after such positions become vacant, may be filled on a part-time career employment basis (including the establishment of criteria to be used in identifying such positions);

"(B) procedures and criteria to be used in connection with establishing or converting positions for part-time career employment, subject to the limitations of section 3393 of this title;

"(C) annual goals for establishing or converting positions for part-time career employment, and a timetable setting forth interim and final deadlines for achieving such goals;

"(D) a continuing review and evaluation of the part-time career employment program established under such regulations; and

"(E) procedures for notifying the public of vacant part-time positions in such agency, utilizing facilities and funds otherwise available to such agency for the dissemination of information.

"(2) The head of each agency shall provide for communication between, and coordination of the activities of, the individuals within such agency whose responsibilities relate to the part-time career employment program established within that agency.

"(3) Regulations established under paragraph (1) of this subsection may provide for such exceptions as may be necessary to carry out the mission of the agency.

"(b)(1) The Civil Service Commission, by regulation, shall establish and maintain a program under which it shall, on the request of an agency, advise and assist such agency in the establishment and maintenance of its part-time career employment program under this subchapter.

"(2) The Commission shall conduct a research and demonstration program with respect to part-time career employment within the Federal Government. In particular, such program shall be directed to—

"(A) determining the extent to which part-time career employment may be used in filling positions which have not traditionally been open for such employment on any extensive basis, such as supervisory, managerial, and professional positions;

"(B) determining the extent to which job-sharing arrangements may be established for various occupations and positions; and

"(C) evaluating attitudes, benefits, costs, efficiency, and productivity associated with part-time career employment, as well as its various sociological effects as a mode of employment.

"§ 3403. Limitations

"(a) An agency shall not abolish any position occupied by an employee in order to make the duties of such position available to be performed on a part-time career employment basis.

"(b) Any person who is employed on a full-time basis in an agency shall not be required to accept part-time employment as a condition of continued employment.

"§ 3404. Personnel ceilings

"In administering any personnel ceiling applicable to an agency (or unit therein), an employee employed by such agency on a part-time career employment basis shall be counted as a fraction which is determined by dividing 40 hours into the average number of hours of such employee's regularly scheduled workweek. This section shall become effective on October 1, 1980.

"§ 3405. Nonapplicability

"(a) If, on the date of enactment of this subchapter, there is in effect with respect to positions within an agency a collective-bargaining agreement which establishes the number of hours of employment a week, then this subchapter shall not apply to those positions.

"(b) This subchapter shall not require part-time career employment in positions the rate of basic pay for which is fixed at a rate equal to or greater than the minimum rate fixed for GS-16 of the General Schedule.

"§ 3406. Regulations

"Before any regulation is prescribed under this subchapter, a copy of the proposed regulation shall be published in the Federal Register and an opportunity provided to interested parties to present written comment and, where practicable, oral comment. Initial regulations shall be prescribed not later than 180 days after the date of the enactment of this subchapter.

"§ 3407. Reports

"(a) Each agency shall prepare and transmit on a biannual basis a report to the Office of Personnel Management on its activities under this subchapter, including—

"(1) details on such agency's progress in meeting part-time career employment goals established under section 3392 of this title; and

"(2) an explanation of any impediments experienced by such agency in meeting such goals or in otherwise carrying out the provisions of this subchapter, together with a statement of the measures taken to overcome such impediments.

"(b) The Commission shall include in its annual report under section 1308 of this title a statement of its activities under this subchapter, and a description and evaluation of the activities of agencies in carrying out the provisions of this subchapter.

"§ 3408. Employee organization representation

"If an employee organization has been accorded exclusive recognition with respect to a unit within an agency, then the employee organization shall be entitled to represent all employees within that unit employed on a part-time career employment basis.".

(b) Subpart B of the table of chapters of part III of the analysis of chapter 33 of title 5, United States Code, is amended by inserting after the item relating to section 3385 the following:

"SUBCHAPTER VII—PART-TIME CAREER EMPLOYMENT OPPORTUNITIES

Sec. 4. (a) Section 8347(g) of title 5, United States Code, is amended by adding at the end thereof the following: "However, the Commission may not exclude any employee who occupies a position on a part-time career employment basis (as defined in section 3391(2) of this title).".

(b) Section 8716(b) of such title 5 is amended—

(1) by striking out of the second sentence "or part-time";

(2) by striking out "or" at the end of clause (1);

(3) by striking out the period at the end of clause (2) and inserting in lieu thereof "; or"; and

(4) by adding at the end thereof the following:

"(3) an employee who is occupying a position on a part-time career employment basis (as defined in section 3391(2) of this title).".

(c)(1) Section 8913(b) of such title 5 is amended—

(A) by striking out "or" at the end of clause (1);

(B) by striking out the period at the end of clause (2) and inserting in lieu thereof "; or"; and

(C) by adding at the end thereof the following:

"(3) an employee who is occupying a position on a part-time career employment basis (as defined in section 3391(2) of this title).".

(2)(A) Section 8906(b) of such title 5 is amended—

(i) by striking out "paragraph (2)" in paragraph (1) and inserting in lieu thereof "paragraphs (2) and (3)"; and

(ii) by adding at the end thereof the following new paragraph:

"(3) In the case of an employee who is occupying a position on a part-time career employment basis (as defined in section 3391 (2) of this title), the biweekly Government contribution shall be equal to the percentage which bears the same ratio to the percentage determined under this subsection (without regard to this paragraph) as the average number of hours of such employee's regularly scheduled workweek bears to the average number of hours in the regularly scheduled workweek of an employee serving in a comparable position on a full-time career basis (as determined under regulations prescribed by the Commission)".

(B) The amendments made by subparagraph (A) shall not apply with respect to any employee serving in a position on a part-time career employment basis on the date of the enactment of this Act for such period as the employee continues to serve without a break in service in that or any other position on such part-time basis.

Sec. 5. Each report prepared by an agency under section 3397(a) of title 5, United States Code (as added by this Act), shall, to the extent to which part-time career employment opportunities have been extended by such agency during the period covered by such report to each group referred to in subparagraphs (A), (B), (C), and (D), of section 2(a)(2) of this Act.

Subpart B—Regulatory Requirements of the Office of Personnel Management

§ 340.201 Regulatory requirements.

This subpart contains the regulations of the Office of Personnel Management which implement the above sections of chapter 34 (as set out in § 340.101).

§ 340.202 General.

(a) *Definitions.* "Part-time career employment" means regularly scheduled work of from 16 to 32 hours per week performed by an employee of an agency as defined in 5 U.S.C. 3401 (a) through (f), who has an appointment in tenure group I or II and who becomes employed on such part-time basis on or after April 8, 1979.

"Tenure group I" applies to employees in the competitive service under career appointments who are not serving probation and permanent employees in the excepted service whose appointments carry no restrictions or conditions.

"Tenure group II" applies to employees in the competitive service serving probation, career-conditional employees, and career employees in obligated positions. It also includes employees in the excepted service serving trial periods, whose tenure is indefinite solely because they occupy obligated positions; or whose tenure is equivalent to career-conditional in the competitive service.

(b) *Agency Exceptions.* As an exception to the general definition of part-time employment in § 340.202(a) and under the authority provided in 5 U.S.C. 3402(a)(3), an agency may permit an employee who has an appointment in tenure group I or II to perform regularly scheduled work of from 1 to 15 hours per week.

(c) *Mixed Tours of Duty.* The provisions of this subpart and the term "part-time career employment" do not apply to employees with appointments in tenure groups I or II who work under mixed tours of duty. A mixed tour of duty consists of annually recurring periods of full-time, part-time or intermittent service.

§ 340.203 Technical assistance.

(a) The Office of Personnel Management shall provide, within available resources, consultation and technical advice and assistance to agencies to aid them in expanding career part-time employment opportunities. This assistance shall include but not be limited to:

(1) Help in developing part-time career employment programs;

(2) Information on public and private sector part-time employment practices;

(3) Development of special recruitment and selection techniques for filling part-time positions;

(4) Interpretations of part-time employment law, regulations and policy;

(5) Guidance on job sharing and position restructuring.

(b) Request for information and assistance should be directed to the Associate Director for Staffing Services, Office of Personnel Management, 1900 E Street, NW., Washington, D.C. 20415, or the nearest OPM regional office.

§ 340.204 Agency reporting.

(a) Agency reports required under 5 U.S.C. 3407 shall be based on data as of March 31 and September 30 each year and shall be provided to the Office of Personnel Management no later than May 15 and November 15 respectively.

(b) Each agency shall include with such reports a copy of any agencywide part-time career employment program regulations and instructions issued during the 6-month period preceding the report date.

(c) Reports should be sent to the Associate Director for Staffing Services, Office of Personnel Management, 1900 E Street, NW., Washington, D.C. 20415.

PART 890—FEDERAL EMPLOYEES HEALTH BENEFITS PROGRAM

(2) Part 890 of the regulations is amended: (a) By redesignating § 890.102(d) as § 890.102(e) and adding a new paragraph (d); and (b) by adding a new paragraph (v) to § 890.301, as set out below.

§ 890.102 Coverage.

* * * * *

(d) Paragraph (c) of this section does not deny coverage to an individual appointed to perform "part-time career employment," as defined in section 3401(2) of title 5, United States Code, and 5 CFR Part 340, Subpart B.

(e) The Office of Personnel Management makes the final determination of the applicability of this section to specific employees or groups of employees.

(33 FR 12510, September 4, 1968, as amended at 33 FR 20002, December 31, 1968; 35 FR 753, January 20, 1970.)

§ 890.301 Opportunities to register to enroll and change enrollment.

* * * * *

(v) *Change to part-time career employment.* An enrolled employee who moves, without a break in service or after a separation of 3 days or less, to "part-time career employment" as defined in section 3401(2) of title 5, United States Code, and 5 CFR Part 340, Subpart B, may change to any other plan or option. This change in enrollment may be made within 31 days after the change to "part-time career employment."

(33 FR 12510, September 4, 1968, as amended at 41 FR 40090, September 17, 1976; 41, FR

52043, November 26, 1976; 42 FR 52373, September 30, 1977.)

[FR Doc. 79-30938 Filed 10-4-79; 8:45 am]

BILLING CODE 6325-01-M

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

7 CFR Part 910

[Lemon Reg. 220]

Lemons Grown in California and Arizona; Limitation of Handling

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Final rule.

SUMMARY: This regulation establishes the quantity of fresh California-Arizona lemons that may be shipped to market during the period October 7–13, 1979. Such action is needed to provide for orderly marketing of fresh lemons for this period due to the marketing situation confronting the lemon industry.

EFFECTIVE DATE: October 7, 1979.

FOR FURTHER INFORMATION CONTACT: Malvin E. McGaha, 202-447-5975.

SUPPLEMENTARY INFORMATION: *Findings.* This regulation is issued under the marketing agreement, as amended, and Order No. 910, as amended (7 CFR Part 910), regulating the handling of lemons grown in California and Arizona. The agreement and order are effective under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601-674). The action is based upon the recommendations and information submitted by the Lemon Administrative Committee, and upon other information. It is hereby found that this action will tend to effectuate the declared policy of the act.

The committee met on October 2, 1979, to consider supply and market conditions and other factors affecting the need for regulation and recommended a quantity of lemons deemed advisable to be handled during the specified week. The committee reports the demand for lemons is easier.

It is further found that it is impracticable and contrary to the public interest to give preliminary notice, engage in public rulemaking, and postpone the effective date until 30 days after publication in the Federal Register (5 U.S.C. 553), because of insufficient time between the date when information became available upon which this regulation is based and the effective date necessary to effectuate the declared policy of the act. Interested persons were given an opportunity to submit information and views on the regulation at an open meeting. It is necessary to effectuate the declared purposes of the act to make these regulatory provisions effective as specified, and handlers have been apprised of such provisions and the effective time.

Further, in accordance with procedures in Executive Order 12044, the emergency nature of this regulation warrants publication without opportunity for further public comment. The regulation has not been classified significant under USDA criteria for implementing the Executive Order. An Impact Analysis is available from Malvin E. McGaha, 202-447-5975.

§ 910.520 Lemon Regulation 220.

Order. (a) The quantity of lemons grown in California and Arizona which may be handled during the period October 7, 1979, through October 13, 1979, is established at 200,000 cartons.

(b) As used in this section, "handled" and "carton(s)" mean the same as defined in the marketing order.

(Secs. 1-19, 48 Stat. 31, as amended; (7 U.S.C. 601-674))

Dated: October 3, 1979.

D. S. Kuryloski,

Deputy Director, Fruit and Vegetable Division, Agricultural Marketing Service.

[FR Doc. 79-31108 Filed 10-4-79; 8:45 am]

BILLING CODE 3410-02-M

Commodity Credit Corporation

7 CFR Part 1421

[CCC Grain Price Support Regs., Grain Reserve Program Supplement, Amd. 2]

Regulations Governing the Grain Reserve Program for 1976 and Subsequent Crops

AGENCY: Commodity Credit Corporation, USDA.

ACTION: Final rule.

SUMMARY: This rule contains provisions whereby the Secretary may offer producers, under certain circumstances, the options of (1) delaying their date for settlement of called reserve loans and (2) the reentry of such loans into the reserve loan program.

The delayed settlement provision is needed to promote orderly marketing of called reserve loans as intended by the reserve program. The present 30-day period allowed for redemption of called reserve commodities has proven inadequate to permit producers to redeem and market their grain in an orderly manner. When transportation problems and/or storage problems occur in an area, notwithstanding the national average market price being at call level or above, producers are often prevented from marketing the commodity in order to repay their loans. Delayed settlements will allow producers to hold their reserve commodities until disruption of orderly marketing eases and better prices may be obtained.

The reentry of called reserve loans into the reserve is also needed to ensure that producers receive the intended benefits of the reserve program which is to hold their stocks and take advantage of higher prices. Sharply declining market prices below reserve release level subsequent to the call of a reserve commodity deprives the producer this opportunity.

EFFECTIVE DATE: October 5, 1979.

ADDRESS: Price Support and Loan Division, ASCS, USDA, 3741 South Building, P.O. Box 2415, Washington, D.C. 20013.

FOR FURTHER INFORMATION CONTACT: Harold Jamison, ASCS, (202) 447-7973.

SUPPLEMENTARY INFORMATION: On July 27, 1979, the Secretary of Agriculture authorized State and county ASC committees to give producers the option of delaying settlement of reserve barley and oat loans called in areas where orderly marketing is disrupted. Disruption to orderly marketing has occurred in the major barley and oat producing areas caused by the shortage of railcars, the recent strike by independent truckers, and by the elevator operator strike in the Duluth-Superior area.

On August 3, 1979, the Secretary authorized, at producers option, the reentry of oats loans into the Grain Reserve Program. Such action is deemed appropriate for any called reserve grain when market prices for such grain fall below the release level as it has for oats. The intent of the reserve program as provided in Section 110 of the Agriculture Act of 1949, as added by the Food and Agricultural Act of 1977, is to allow producers to hold their stocks when such commodities are in abundant supply and extend the time period for their orderly marketing. A sudden decline in market prices below reserve release level subsequent to the call of a reserve commodity disrupts orderly marketing and defeats the purpose of the reserve program.

Final Rule

Accordingly, 7 CFR Part 1421 is amended by revising Section 1421.543(c) as follows:

§ 1421.543 Release levels, redemption, requirements, and early redemption charges.

* * * * *

(c) Redemption of commodity when the national average market price is at least 175 percent for wheat or 140 percent for feed grain of national average loan rate.

(1) When CCC determines that the national average market price is at least 175 percent for wheat or 140 percent for feed grain of the national average loan rate, the loan shall be called. Such call will be determined in the same manner as prescribed for release levels in § 1421.543(a). If the loan is not redeemed within 30 days after notification, CCC may take title to the commodity.

(2) Notwithstanding any provision of this subpart, with respect to loans called under paragraph (c)(1) of this section, the Secretary may provide producers the options of (i) delaying their date for settlement of such loans for a period of 30 days and such additional 30-day periods as determined necessary by the Secretary in areas where the Secretary determines conditions exist which disrupt orderly marketing of the commodity under loan and (ii) reentering the loan into the reserve loan program under all the original terms and conditions, if subsequent to such loan call the national average market price of the loan commodity falls below the release level applicable to the loan commodity.

* * * * *

Note.—Because orderly marketing of barley and oats in the Grain Reserve Program has been disrupted by transportation and related problems in certain areas and the national average market price for oats has declined since reaching the call level, producers need to know immediately these reserve program provisions.

Therefore, pursuant to the administrative procedure provisions in 5 U.S.C. 553, it is found upon good cause that notice and other public procedure with respect to this final rule are impracticable and contrary to the public interest.

Further, this final rule has not been designated as "significant," and is being published in accordance with the emergency procedures in Executive Order 12044 and Secretary's Memorandum 1955. It has been determined by Jerome F. Sitter, Director, Price Support and Loan Division, that the emergency nature of this final rule warrants publication without opportunity for public comment and preparation of an impact analysis statement at this time.

This final rule will be scheduled for review under provisions of Executive Order 12044 and Secretary's Memorandum 1955.

Dated: September 26, 1979.

Bob Bergland,

Secretary of Agriculture.

[FR Doc. 79-30567 Filed 10-4-79; 8:45 am]

BILLING CODE 3410-05-M

Animal and Plant Health Inspection Service

9 CFR Part 78

Brucellosis Areas

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Final rule.

SUMMARY: These amendments add the county of Knox in Illinois and Dona Ana in New Mexico, to the list of Certified Brucellosis-Free Areas and delete such counties from the list of Modified Certified Brucellosis Areas. It has been determined that these counties qualify to be designated as Certified Brucellosis-Free Areas. The effect of this action will allow for less restrictions on cattle moved interstate from these areas. These amendments also add the county of Faulk in South Dakota, to the list of Modified Certified Brucellosis Areas and delete it from the list of Certified Brucellosis-Free Areas because it has been determined that this county now qualifies only as a Modified Certified Brucellosis Area. The effect of this action will provide for more restrictions on cattle and bison moved interstate from this area.

EFFECTIVE DATE: October 5, 1979.

FOR FURTHER INFORMATION CONTACT: Dr. A. D. Robb, USDA, APHIS, VS, Room 805, 6505 Belcrest Road, Hyattsville, MD 20782, 301-436-8713.

SUPPLEMENTARY INFORMATION: A complete list of brucellosis areas was published in the Federal Register (44 FR 36373-36375) effective June 22, 1979. These amendments add the county of Knox in Illinois and Dona Ana in New Mexico, to the list of Certified Brucellosis-Free Areas in § 78.20 and delete such counties from the list of Modified Certified Brucellosis Areas in § 78.21, because it has been determined that they now come within the definition of a Certified Brucellosis-Free Area contained in § 78.1(l) of the regulations. These amendments add the county of Faulk in South Dakota to the list of Modified Certified Brucellosis Areas in § 78.21 and delete this county from the list of Certified Brucellosis-Free Areas in § 78.20, because it has been determined that it now qualifies only as a Modified Certified Brucellosis Area as defined in § 78.1(m) of the regulations. This list is updated monthly and reflects actions taken under criteria for designating areas according to brucellosis status.

Accordingly, Part 78, Title 9, Code of Federal Regulations, is hereby amended in the following respects:

§ 78.20 [Amended]

1. In § 78.20, paragraph (b) is amended by adding: *Illinois.* Knox; *New Mexico.* Dona Ana; and deleting: *South Dakota.* Faulk.

§ 78.21 [Amended]

2. In § 78.21, paragraph (b) is amended by adding: *South Dakota.* Faulk; and by deleting: *Illinois.* Knox; *New Mexico.* Dona Ana.

(Secs. 4-7, 23 Stat. 32, as amended; secs. 1 and 2, 32 Stat. 791-792, as amended; sec. 3, 33 Stat. 1265, as amended; sec. 2, 65 Stat. 693; and secs. 3 and 11, 76 Stat. 130, 132; 21 U.S.C. 111-113, 114a-1, 115, 117, 120, 121, 125, 134b, 134f, 37 FR 28464, 28477; 38 FR 19141, 9 CFR 78.25.)

The amendment designating areas as Certified Brucellosis-Free Areas relieves restrictions presently imposed on cattle moved from the areas in interstate commerce.

The restrictions are no longer deemed necessary to prevent the spread of brucellosis from such areas and, therefore, the amendment should be made effective immediately in order to permit affected persons to move cattle interstate from such areas without unnecessary restrictions.

The amendment designating an area as a Modified Certified Brucellosis Area imposes restrictions presently not imposed on cattle and bison moved from that area in interstate commerce. The restrictions are necessary in order to prevent the spread of brucellosis from such area.

Therefore, pursuant to the administrative procedure provisions in 5 U.S.C. 553, it is found upon good cause that notice and other public procedure with respect to this final rule are impracticable and contrary to the public interest and good cause if found for making this final rule effective less than 30 days after publication of this document in the Federal Register.

Further, this final rule has not been designated as "significant," and is being published in accordance with the emergency procedures in Executive Order 12044 and Secretary's Memorandum 1955. It has been determined by Paul Becton, Director, National Brucellosis Eradication Program, APHIS, VS, USDA, that the emergency nature of this final rule warrants publication without opportunity for public comment and preparation of an impact analysis statement at this time.

This final rule will be scheduled for review under provisions of Executive Order 12044 and Secretary's Memorandum 1955.

Done at Washington, D.C., this 27th day of September 1979.

E. A. Schilf,

Acting Deputy Administrator, Veterinary Services.

[FR Doc. 79-30637 Filed 10-4-79; 8:45 am]

BILLING CODE 3410-34-M

FEDERAL RESERVE SYSTEM

12 CFR Part 201

Extensions of Credit by Federal Reserve Banks; Changes in Discount Rates

AGENCY: Board of Governors of the Federal Reserve System.

ACTION: Final rule.

SUMMARY: The Board of Governors has amended its Regulation A, "Extensions of Credit By Federal Reserve Banks," for the purpose of adjusting discount rates with a view to accommodating commerce and business in accordance with other related rates and the general credit situation of the country.

EFFECTIVE DATE: The changes were effective on the dates specified below.

FOR FURTHER INFORMATION CONTACT: Theodore E. Allison, Secretary, Board of Governors of the Federal Reserve System, Washington, D.C. 20551 (202/452-3257)

SUPPLEMENTARY INFORMATION: Pursuant to the authority of 5 U.S.C. Sec. 553(b)(3)(B) and (d)(3), these amendments are being published without prior general notice of proposed rulemaking, public participation, or deferred effective date. The Board has for good cause found that current economic and financial considerations required that these amendments be adopted immediately.

Pursuant to section 14(d) of the Federal Reserve Act (12 U.S.C. 357), Part 201 is amended as set forth below:

1. Section 201.51 is amended to read as follows:

§ 201.51 Advances and discounts for member banks under sections 13 and 13a.

The rates for all advances and discounts under sections 13 and 13a of the Federal Reserve Act (except advances under the last paragraph of such section 13 to individuals, partnerships, or corporations other than member banks) are:

Federal Reserve Bank	Rate	Effective
Boston	11	Sept. 19, 1979.
New York	11	Sept. 19, 1979.
Philadelphia	11	Sept. 21, 1979.
Cleveland	11	Sept. 19, 1979.
Richmond	11	Sept. 19, 1979.
Atlanta	11	Sept. 19, 1979.
Chicago	11	Sept. 19, 1979.
St. Louis	11	Sept. 19, 1979.
Minneapolis	11	Sept. 19, 1979.
Kansas City	11	Sept. 20, 1979.
Dallas	11	Sept. 19, 1979.
San Francisco	11	Sept. 19, 1979.

2. Section 201.52 is amended to read as follows:

§ 201.52 Advances to member banks under section 10(b).

(a) The rates for advances to member banks under section 10(b) of the Federal Reserve Act are:

Federal Reserve Bank	Rate	Effective
Boston	11½	Sept. 19, 1979.
New York	11½	Sept. 19, 1979.
Philadelphia	11½	Sept. 21, 1979.
Cleveland	11½	Sept. 19, 1979.
Richmond	11½	Sept. 19, 1979.
Atlanta	11½	Sept. 19, 1979.
Chicago	11½	Sept. 19, 1979.
St. Louis	11½	Sept. 19, 1979.
Minneapolis	11½	Sept. 19, 1979.
Kansas City	11½	Sept. 20, 1979.
Dallas	11½	Sept. 19, 1979.
San Francisco	11½	Sept. 19, 1979.

(b) The rates for advances to member banks for prolonged periods and significant amounts under section 10(b) of the Federal Reserve Act and section 201.2(e)(2) of Regulation A are:

Federal Reserve Bank	Rate	Effective
Boston	12	Sept. 19, 1979.
New York	12	Sept. 19, 1979.
Philadelphia	12	Sept. 21, 1979.
Cleveland	12	Sept. 19, 1979.
Richmond	12	Sept. 19, 1979.
Atlanta	12	Sept. 19, 1979.
Chicago	12	Sept. 19, 1979.
St. Louis	12	Sept. 19, 1979.
Minneapolis	12	Sept. 19, 1979.
Kansas City	12	Sept. 20, 1979.
Dallas	12	Sept. 19, 1979.
San Francisco	12	Sept. 19, 1979.

3. Section 201.53 is amended to read as follows:

§ 201.53 Advances to persons other than member banks.

The rates for advances under the last paragraph of section 13 of the Federal Reserve Act to individuals, partnerships, or corporations other than member banks secured by direct obligations of, or obligations fully guaranteed as to principal and interest by, the United States or any agency thereof are:

Federal Reserve Bank	Rate	Effective
Boston	14	Sept. 19, 1979.
New York	14	Sept. 19, 1979.
Philadelphia	14	Sept. 21, 1979.
Cleveland	14	Sept. 19, 1979.
Richmond	14	Sept. 19, 1979.
Atlanta	14	Sept. 19, 1979.
Chicago	14	Sept. 19, 1979.
St. Louis	14	Sept. 19, 1979.
Minneapolis	14	Sept. 19, 1979.
Kansas City	14	Sept. 20, 1979.
Dallas	14	Sept. 19, 1979.
San Francisco	14	Sept. 19, 1979.

(12 U.S.C. 248(i). Interprets or applies 12 U.S.C. 357.)

By order of the Board of Governors, September 24, 1979.

Theodore E. Allison,

Secretary of the Board.

[FR Doc. 79-30742 Filed 10-4-79; 8:45 am]

BILLING CODE 6210-01-M

FEDERAL DEPOSIT INSURANCE CORPORATION

12 CFR Part 346

AGENCY: Federal Deposit Insurance Corporation (FDIC).

ACTION: Final rule.

SUMMARY: FDIC's Board of Directors adopts an appendix to Part 346 of FDIC's regulations (12 CFR Part 346) to set out which States require State chartered banks to have deposit insurance. The purpose of this appendix is to advise the general public and the foreign banking community of the States wherein State branches of foreign banks will be subject to FDIC's mandatory insurance requirement.

EFFECTIVE DATE: October 5, 1979.

FOR FURTHER INFORMATION CONTACT: John F. Breyer, Office of the General Counsel, Federal Deposit Insurance Corporation, 550 17th Street NW., Washington, D.C. 20429 (202-389-4616).

SUPPLEMENTARY INFORMATION: Final rules implementing the International Banking Act of 1978 were adopted by the Board on June 28, 1979 (12 CFR Part 346, 44 FR 40056). These rules require State branches of foreign banks (not otherwise exempt), which are located in a State which requires State banks to have deposit insurance, to obtain FDIC insurance if they accept initial deposits of less than $100,000. In order to determine which States require State banks to have deposit insurance, each State bank supervisor was requested to advise the FDIC as to the requirements of that State. Under FDIC's rules, the State requirement for deposit insurance may be imposed by State statute or by banking department regulation or policy; and, the deposit insurance requirement includes State deposit insurance programs as well as FDIC insurance.

This appendix is based on the information provided by the State supervisor in the response to FDIC's request. State branches of foreign banks located in States which do not require State banks to have deposit insurance are not subject to the mandatory insurance provision of Part 346.

Accordingly, pursuant to its authority under § 9 of the Federal Deposit Insurance Act and § 13 of the International Banking Act of 1978 (12 U.S.C. 1819 and 3108) the Board adopts Appendix A to Part 346 of the FDIC regulations as set out below:

Appendix A to Part 346

This Appendix lists the States which require State chartered banks to acquire deposit insurance as a prerequisite to receiving a charter. State branches of foreign banks located in a State requiring State banks to have deposit insurance (unless otherwise exempt) are subject to the mandatory insurance requirement of 12 CFR § 346.4.

States Which Require Deposit Insurance as a Prerequisite to Receiving a Charter*

Alabama, Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Dakota, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Utah, Vermont, Virginia, West Virginia, Wisconsin, Wyoming.

*States Which Do Not Require Deposit Insurance as a Prerequisite to Receiving a Charter**

North Carolina, Texas, Washington.

By order of the board of directors, October 1, 1979.

Federal Deposit Insurance Corporation.

Hoyle L. Robinson,

Executive Secretary.

[FR Doc. 79-30925 Filed 10-4-79; 8:45 am]

BILLING CODE 6714-01-M

*Under FDIC's rules, the State requirement for deposit insurance could be imposed by State statute or banking department regulation or policy.

FEDERAL HOME LOAN BANK BOARD

12 CFR Part 545

[No. 79-497]

Operations; Reduction and Simplification of Regulations; Correction

Dated: October 1, 1979.

AGENCY: Federal Home Loan Bank Board.

ACTION: Final rule.

SUMMARY: These changes correct and clarify the Board's recent revision and simplification of the Rules and Regulations for the Federal Savings and Loan System (44 FR 39108, July 3, 1979).

EFFECTIVE DATE: October 5, 1979.

FOR FURTHER INFORMATION CONTACT: John R. Hall, Attorney, Federal Home Loan Bank Board, 1700 G Street, N.W., Washington, D.C. 20552 (202-377-6445).

SUPPLEMENTARY INFORMATION: The Federal Home Loan Bank Board, by Resolution No. 79-316, dated May 31, 1979, adopted a revision of most of the Rules and Regulations for the Federal Savings and Loan System. The intent of the revision was to simplify the regulations and reduce verbiage. Except in specified instances the revision was not intended to change the substance of the regulations.

The purpose of this document is to correct and clarify the revision. Changes are as follows:

(1) Section 545.6a should remain unchanged.

(2) In § 545.6-3(a)(4), the reference to "the 25 percent limitation in paragraph (a)(3)(iii) of this section" should read "the 25 percent limitation in paragraph (a)(3)(iii) of § 545.6-2," because the referenced limitation appears in § 545.6-2 rather than § 545.6-3.

(3) In § 545.6-3(d)(iv), the phrase "whether fully or partially amortized" should modify the phrase "installment loans" appearing at the end of the first sentence. Deletion of that phrase, which was included in the regulation prior to the revision, appears to effect a substantive change which was not intended.

(4) Sections 545.6-14 through 545.6-26 should be deleted. The substance of those sections was included elsewhere in the revised regulations, and continued inclusion of the old sections would be repetitive.

(5) In § 545.8-3(f), the revised language of the first sentence does not clearly indicate that the sentence merely affirms already existing authority of Federal associations. Therefore, in order to avoid the appearance of a substantive change, the sentence should be more nearly identical to the original language.

Because these changes merely correct the Board's earlier revision of the affected regulations, it has been determined to dispense with (1) notice and public procedure under 5 U.S.C. § 553(b) and 12 CFR 508.11, and (2) publication of the changes for the 30-day period described in 5 U.S.C. § 553(d) and 12 CFR 508.14.

Accordingly, the Board adopts the following corrections to Board Resolution 79-316 (44 FR 39108, July 3, 1979).

1. Revise instructions 8. on page 39120 to read as follows: 8. Revise §§ 545.5, 545.6 and 545.6-1—545.6-3 to read as follows:

2. On page 39122, amend the second sentence of § 545.6-3(a)(4) by deleting the last two words thereof and substituting therefor the term "§ 545.6-2."

3. On page 39122, amend § 545.6-3(d)(3)(iv) by changing the period at the end of the first sentence to a comma, and adding thereafter the following: "whether fully or partially amortized."

4. Revise instruction 11b. on page 39126 to read as follows: 11b. Redesignate § 545.6-27 as § 545.6-13 and delete §§ 545.6-14—545.6-26.

5. On page 39129, amend the first sentence of § 545.8-3(f) to read as follows:

§ 545.8-3 Loan contract.

* * * * *

(f) *Due-on-sale clauses.* An association continues to have the power to include, as a matter of contract between it and the borrower, a provision in its loan instrument whereby the association may, at its option, declare immediately due and payable sums secured by the association's security instrument if all or any part of the real property securing the loan is sold or transferred by the borrower without the association's prior written consent. * * *

* * * * *

(Sec. 5, 48 Stat. 132, as amended (12 U.S.C. 1464). Reorg. Plan No. 3 of 1947, 12 FR 4981, 3 CFR, 1943-48 Comp., p. 1071)

By the Federal Home Loan Bank Board.

J. J. Finn,

Secretary.

[FR Doc. 79-30954 Filed 10-4-79; 8:45 am]

BILLING CODE 6720-01-M

CIVIL AERONAUTICS BOARD

14 CFR Part 212

[Regulation ER-1151; Amendment No. 30]

Charter Trips by Foreign Air Carriers; Notice of Approval by the General Accounting Office

Adopted by the Civil Aeronautics Board at its office in Washington, D.C., October 1, 1979.

AGENCY: Civil Aeronautics Board.

ACTION: Final rule.

SUMMARY: This final rule gives notice that the General Accounting Office has approved the reporting and recordkeeping requirements contained in the subject regulation. This approval is required under the Federal Reports Act, and was transmitted to the Civil Aeronautics Board by letter dated September 7, 1979.

DATES: Adopted: October 1, 1979; Effective: October 1, 1979.

FOR FURTHER INFORMATION CONTACT: Clifford M. Rand, Chief, Data Requirements Division, Office of Economic Analysis, Civil Aeronautics Board, 1825 Connecticut Avenue, N.W., Washington, D.C. 20428, (202) 673-6044.

Accordingly, the Civil Aeronautics Board amends Part 212 of its Economic Regulations (14 CFR 212) by revising the note at the end of Part 212 to read:

Note.—The reporting and recordkeeping requirements contained in sections 212.7, 212.11, 212.13, 212.15, 212.22(b), 212.24, 212.25, 212.31, 212.45, 212.46, 212.47, 212.53, and 212.60 have been approved by the U.S. General Accounting Office under B-180226 (RO656).

This amendment is issued by the undersigned pursuant to the delegation of authority from the Board to the Secretary in 14 CFR sec. 385.24(b). (Sec. 204 of the Federal Aviation Act of 1958, as amended, 72 Stat. 743; 49 U.S.C. 1324).

By the Civil Aeronautics Board.

Phyllis T. Kaylor,

Secretary.

[FR Doc. 79-30952 Filed 10-4-79; 8:45 am]

BILLING CODE 6320-01-M

14 CFR Part 214

[Regulation ER-1152; Amendment No. 27]

Terms, Conditions, and Limitations of Foreign Air Carrier Permits Authorizing Charter Transportation Only; Approval by the General Accounting Office

Adopted by the Civil Aeronautics Board at its office in Washington, D.C., October 1, 1979.

AGENCY: Civil Aeronautics Board.

ACTION: Final rule.

SUMMARY: This final rule gives notice that the General Accounting Office has approved the reporting and recordkeeping requirements contained in the subject regulation. This approval is required under the Federal Reports Act, and was transmitted to the Civil Aeronautics Board by letter dated September 7, 1979.

DATES: Adopted: October 1, 1979; Effective: October 1, 1979.

FOR FURTHER INFORMATION CONTACT: Clifford M. Rand, Chief, Data Requirements Division, Office of Economic Analysis, Civil Aeronautics Board, 1825 Connecticut Avenue, N.W., Washington, D.C. 20428, (202) 673-6044.

Accordingly, the Civil Aeronautics Board amends Part 214 of its Economic Regulations (14 CFR 214) by revising the note at the end of Part 214 to read:

Note.—The reporting and recordkeeping requirements contained in sections 214.3, 214.6, 214.9, 214.9c(a), 214.12(b), 214.13a, 214.17, 214.18, 214.22, 214.35, 214.36, 214.37, 214.43, and 214.50 have been approved by the U.S. General Accounting Office under B-180226 (R0655).

This amendment is issued by the undersigned pursuant to the delegation of authority from the Board to the Secretary in 14 CFR sec. 385.24(b). (Sec. 204 of the Federal Aviation Act of 1958, as amended, 72 Stat. 743, 49 U.S.C. 1324).

By the Civil Aeronautics Board.

Phylis T. Kaylor,

Secretary.

[FR Doc. 79-30953 Filed 10-4-79; 8:45 am]

BILLING CODE 6320-01-M

SECURITIES AND EXCHANGE COMMISSION

17 CFR Parts 240 and 249

[Release No. 34-16235]

Annual Assessment for Non-Member Brokers and Dealers

AGENCY: Securities and Exchange Commission.

ACTION: Final rules.

SUMMARY: The Commission is amending its rules to provide that annual assessments for brokers and dealers that are not members of a registered national securities association shall be the same as corresponding assessments imposed upon member firms, unless the Commission determines otherwise for a particular year. The Commission is also adopting an information and assessment form specifying the annual assessments for non-member brokers and dealers for fiscal 1979.

EFFECTIVE DATE: Effective October 5, 1979. Form SECO-4-79 must be filed, together with the required fees, on or before October 31, 1979.

FOR FURTHER INFORMATION CONTACT: Janet R. Zimmer, Branch Chief, Division of Market Regulation, Securities and Exchange Commission, 500 North Capitol Street, Washington, D.C. 20549 (202) 272-2863.

SUPPLEMENTARY INFORMATION: The Commission today announced the adoption of amendments to Rule 15b9-2 (17 CFR 240.15b9-2) under the Securities Exchange Act of 1934 (the "Act") (15 U.S.C. 78a *et seq.*, as amended by Pub. L. No. 94-29 (June 4, 1975)) and the adoption of Form SECO-4-79 (17 CFR 249.504m) under the Act. Section 15(b)(8) of the Act (15 U.S.C. 78*o*(b)(8)) authorizes the Commission, by rule, to establish and levy such reasonable fees and charges as may be necessary to defray the costs of additional regulatory duties required to be performed with respect to registered broker-dealers who are not members of a registered national securities association ("SECO broker-dealers") and their associated persons.[1] Pursuant to that section, the Commission adopted Securities Exchange Act Rule 15b9-2 which, among other things, requires SECO broker-dealers, on or before September 1 of each year, to file a Form SECO-4 (17 CFR 249.504 *et seq.*) for the particular year and to pay the total annual assessment prescribed by that Form.

The amendments to Rule 15b9-2 being adopted today provide that annual assessments for SECO broker-dealers shall be the same as the corresponding assessments imposed by the National Association of Securities Dealers, Inc. (the "NASD"), the sole registered national securities association, unless the Commission prescribes different rates or levels of assessments for any particular fiscal year. Form SECO-4-79, which specifies the annual fees payable to the Commission by SECO broker-dealers for fiscal year 1979, establishes assessment rates the same as corresponding NASD assessments for the same period.

The amendments to Rule 15b9-2 and Form SECO-4-79 were proposed by the Commission on August 3, 1979 in Securities Exchange Act Release No. 16080 and were published for public comment in the Federal Register on August 16, 1979.[2] Two comments were received in response to the Commission's notice, both opposing the proposed amendments to Rule 15b9-2. One commentator asserted that the proposed amendments, by effectively permitting SECO fees to be set by the NASD, constitute an abandonment by the Commission of its responsibility to maintain reasonable fees to defray the costs of administering the SECO program.[3] He also questioned how the Commission would decide when to

[1] A nonmember broker-dealer who is a member of a national securities exchange may, under limited circumstances, be exempt from this provision. *See* Securities Exchange Act Rules 15b9-1(e) (17 CFR 240.15b9-1(e)) and 15b9-2(e)(3) (17 CFR 240.15b9-2(e)(3)).

[2] 44 FR 47953.

[3] Letter from Alfred J. Hoffman to George A. Fitzsimmons, Secretary of the Commission (August 22, 1979); File No. S7-794.

conduct cost analyses of the SECO program if they did not precede each annual assessment. The second commentator also objected to the proposed amendments.[4] He asserted that they imposed a discriminatory financial burden on smaller SECO broker-dealers by "taxing" them under the same standards as applied to larger firms. No comments were specifically addressed by either commentator to Form SECO-4-79 or the assessment rates proposed for fiscal year 1979.

As noted in the release in which the amendments and form were proposed for comment,[5] it has been the Commission's experience over the past three years that, by setting SECO annual assessments at the same level as corresponding NASD assessments of its members, the Commission has raised approximately the revenues needed to defray the additional regulatory costs of administering its SECO program. It is the Commission's belief that, for the most part, the costs of administering the SECO program are likely to continue to warrant the imposition of fees at rates similar to those assessed by the NASD. In addition, the Congress has indicated an intention that SECO broker-dealers be subject to regulation comparable to the NASD's regulation of its members.[6]

It is, of course, possible that circumstances may arise in which the costs of administration of the SECO program may require assessments that differ from those charged by the NASD. The amendments to Rule 15b9-2 preserve the Commission's authority under the Act to exercise the flexibility needed in such circumstances to impose fees on SECO broker-dealers that differ from comparable NASD assessments. The Commission is confident that, as part of its continuing operation of the SECO program the Commission will recognize any occasion where it would be appropriate to consider whether SECO assessments should differ from NASD member fees.

The Commission does not believe that the imposition of these fees results in a discriminatory burden on smaller broker-dealers. Only one element of the SECO annual assessment, a flat fee of $250, does not vary with the size of the firm. This reflects the fact that certain costs, such as the processing of forms and mailing of notices, are substantially the same regardless of the size of the firm. The second part of the assessment, a $5 fee per associated person, would vary in direct proportion to the number of persons engaged in securities activities for the firm. The third element is a fee set as a percentage of the gross income of the firm. The latter two fees are intended to cover costs that generally would be affected by the size of the firm. Taken together, these fees are designed reasonably to defray both those administrative costs that generally do not vary, as well as those that are affected by the size of the firm.

The Commission received no comments regarding Form SECO-4-79 or the levels of assessments proposed for fiscal 1979. The first two elements of the assessments—the flat $250 charge per firm and $5 fee per associated person—have not been raised from fiscal 1978. The gross income assessment, however, has been increased from 0.17% to 0.19% for municipal securities transactions and from 0.21% to 0.23% for other over-the-counter transactions. These assessments are set at the same levels as the NASD's assessments for fiscal 1979. To allow for public notice and comment on the amendments to Rule 15b9-2 under the Act and Form SECO-4-79, the deadline for payment of assessments has been extended until October 31, 1979.

The Securities and Exchange Commission, acting pursuant to the Act, and particularly Sections 15 and 23 thereof (15 U.S.C. 78*o* and 78w), hereby adopts amendments to § 240.15b9-2 of Title 17 of the Code of Federal Regulations, and also adopts Form SECO-4-79 under § 249.504m of Title 17 of the Code of Federal Regulations, effective today.

The Commission finds that the amendments to Rule 15b9-2 and Form SECO-4-79 do not impose any burdens on competition not necessary or appropriate in furtherance of the purposes of the Act. Rule 15b9-2, by providing that annual assessments for SECO broker-dealers shall be the same as corresponding assessments on NASD members, unless otherwise determined for a particular year, in fact promotes competition between SECO broker-dealers and NASD member broker-dealers by ensuring that the fees to which they are subject will generally be comparable, unless a cost analysis reveals that differing assessments are warranted in particular years. The annual assessments for SECO broker-dealers for fiscal 1979, as set forth in Form SECO-4-79, are the same as corresponding NASD assessments.

[4] Letter from Milton S. Traubner to George A. Fitzsimmons, Secretary of the Commission (September 3, 1979); File No. S7-794.

[5] Securities Exchange Act Release No. 16080 (August 3, 1979), 44 FR 47953, 47954 (August 16, 1979)

[6] H. Rep. No. 1418, 88th Cong., 2d Sess. at 12.

PART 240—GENERAL RULES AND REGULATIONS, SECURITIES EXCHANGE ACT OF 1934

1. 17 CFR Part 240 is amended by revising paragraph (b) of § 240.15b9-2 to read as follows:

§ 240.15b9-2 Annual assessment for registered brokers and dealers not members of a registered securities association.

* * * * *

(b)(1) *Assessments.* On or before September 1 of each year, every broker or dealer to whom this rule applies shall file the Form SECO-4 provided for the particular fiscal year and pay the total assessments prescribed by the form. Such assessments shall include: (i) A flat fee basic assessment applicable to all brokers or dealer, (ii) a gross income assessment applicable to all brokers or dealers based upon the broker or dealer's gross income during the preceding calendar year, and (iii) an assessment for each associated person engaged, directly or indirectly, in securities activities for or on behalf of the broker or dealer prior to August 15 during the fiscal year, at any time in which the broker or dealer was a non-member broker or dealer: *Provided, however,* That the assessment shall not be paid for any person who confines his securities activities to areas outside the United States, its territories and possessions, and who does not deal with or act for any U.S. resident or national wherever located.

(2) *Levels or rates of assessments.* The levels or rates of assessments shall be the same as the corresponding assessments imposed by the National Association of Securities Dealers, Inc. upon its members during that fiscal year, unless the Commission prescribes different rates or levels of assessment in the Form SECO-4 for that fiscal year.

* * * * *

PART 249—FORMS, SECURITIES EXCHANGE ACT OF 1934

2. 17 CFR Part 249 is amended by adding a new § 249.504m to read as follows:

§ 249.504m Form SECO-4-79, assessment and information form for registered brokers and dealers not members of a registered national securities association.

This form shall be filed on or before October 31, 1979, pursuant to § 240.15b9-2 of this chapter, accompanied by the annual assessment fee required thereunder and as specified in this form, for the fiscal year ended

September 30, 1979, by every registered national securities association.

* * * * *

Copies of Form SECO-4-79 (17 CFR 249.504m) will be forwarded to SECO broker-dealers. Copies of the form have been filed with the Office of the Federal Register and additional copies are available on request by contacting William Finegan, Office of Reports and Information Services, Securities and Exchange Commission, Washington, D.C., 20549.

(Secs. 15 and 23 (15 U.S.C. 78o and 78w).)

By the Commission.

George A. Fitzsimmons,

Secretary.

October 2, 1979.

[FR Doc. 79-31013 Filed 10-4-79; 8:45 am]

BILLING Code 8010-01-M

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE

Food and Drug Administration

21 CFR Part 109

[Docket No. 77N-0080]

Unavoidable Contaminants in Food for Human Consumption and Food-Packaging Materials; Polychlorinated Biphenyls (PCB's); Reduction of Tolerances; Confirmation of Effective Date and Partial Stay

AGENCY: Food and Drug Administration

ACTION: Final Rule.

SUMMARY: This document announces that the effective date of the final regulation reducing tolerances for unavoidable residues of the industrial chemicals polychlorinated biphenyls in certain foods is confirmed, except that the provision concerning fish and shellfish is stayed. The stay of the reduced tolerance for fish and shellfish is in effect pending a resolution of the issues raised by an objection filed by the National Fisheries Institute, Inc. A notice specifying the issues, if any, for which a hearing is justified and other pertinent information will be published in the Federal Register at a later date.

EFFECTIVE DATE: The final regulation became effective on August 28, 1979, except the provision concerning fish and shellfish (§ 109.30(a)(7)) is stayed until further notice.

FOR FURTHER INFORMATION CONTACT: Elizabeth Campbell, Bureau of Foods (HFF-312), Food and Drug Administration, Department of Health, Education, and Welfare, 200 C St. SW., Washington, DC 20204, 202-245-3092.

SUPPLEMENTARY INFORMATION: In the Federal Register of June 29, 1979 (44 FR 38330), the agency issued a final regulation reducing tolerances for unavoidable residues of the industrial chemicals polychlorinated biphenyls (PCB's) in several classes of food.

The final regulation provided that the tolerance for PCB's is 1.5 parts per million (ppm) in milk (fat basis), 1.5 ppm for PCB's in dairy products (fat basis), 3 ppm in poultry (fat basis), 0.3 ppm in eggs, and 2 ppm in fish and shellfish (edible portion).

Objection and Request for a Hearing

As provided by law, persons who would be adversely affected by the final regulation were given the opportunity to file written objections on or before July 30, 1979 and, if desired, request a formal, evidentiary hearing on the specific provisions to which they objected.

The agency received over 20 timely objections to the final regulation, all of which dealt with the tolerance for fish and shellfish (§ 109.30(a)(7)). Only one objection, which was submitted by the National Fisheries Institute, Inc. (NFI) in concert with several other organizations, was coupled with a request for the formal hearing provided for in the statute (21 U.S.C. 371(e)(2)). The NFI objection and request for a hearing on § 109.30(A)(7) is based essentially on a contention that the agency grossly underestimated the loss of food that would result from the reduced tolerance for fish and shellfish. According to the Institute, this underestimate resulted in the agency inadequately assessing the "avoidability" of PCB's as a factor in its deliberations as to the correct tolerance level.

Another objection expressed the concern that not all persons interested in fishing had had an opportunity to comment on the final regulation during the 30 days allowed for the filing of objections, and it requested that a hearing be held (in the Great Lakes region, if possible) "to give the people most directly affected a chance to participate." FDA does not interpret this as a request for the formal, trial-type hearing provided for in 21 U.S.C. 371(e)(2), but rather as a request that FDA extend the period for filing objections and hold informal hearings as a mechanism for receiving additional comments and objections on the final regulation. FDA will respond to this request, as well as the points raised in all the other objections it received, in a future Federal Register document announcing the agency's response to NFI's request for a hearing.

Regulation Stayed

By operation of statute (21 U.S.C. 371(e)(2)), the objection and request for hearing filed by NFI, stays the effective date of the revised fish and shellfish tolerance in § 109.30(a)(7) pending resolution of the issues raised in the objection. Because no objections and requests for hearing were received on the other provisions of the reduced tolerance regulation, those other provisions went into effect, as scheduled, on August 28, 1979.

The agency is now in the process of considering whether a hearing is necessary to resolve the issues raised in the NFI objection. A notice stating any issues on which a hearing is justified and setting forth other pertinent information will be published in the Federal Register at a later date. A copy of all the objections is on file in the office of the Hearing Clerk (HFA-305), Food and Drug Administration, Rm. 4-65, 5600 Fishers Lane, Rockville, MD 20857. The NFI objection is identifed as OB0015.

Therefore, under the Federal Food, Drug, and Cosmetic Act (secs. 306, 402(a), 406, 701 (a) and (e), 52 Stat. 1045-1046 as amended, 1049 as amended, 1055, 70 Stat. 919 as amended (21 U.S.C. 336, 342,(a) 346, 371 (a) and (e))) and under authority delegated to the Commissioner of Food and Drugs (21 CFR 5.1), notice is given that § 109.30(a)(1) through (4) and (b) became effective August 28, 1979; an objection and request for a hearing was filed concerning the reduced tolerance for PCB's in fish and shellfish, and § 109.30(a)(7) is thus stayed until further notice.

Dated: September 28, 1979.

Joseph P. Hile,

Associate Commissioner for Regulatory Affairs.

[FR Doc. 79-30872 Filed 10-2-79; 11:29 am]

BILLING CODE 4110-03-M

21 CFR Parts 510 and 558

Animal Drugs, Feeds, and Related Products; Cargill, Inc.; Change of Sponsor

AGENCY: Food and Drug Administration.

ACTION: Final rule.

SUMMARY: The animal drug regulations are amended to reflect the change of sponsor for a tylosin premix from Neese & Sons, Inc., to Cargill, Inc. A supplemental new animal drug application (NADA) filed by Neese & Sons, Inc., provides for this change.

EFFECTIVE DATE: October 5, 1979.

FOR FURTHER INFORMATION CONTACT: Jack C. Taylor, Bureau of Veterinary Medicine (HFV-136), Food and Drug Administration, Department of Health, Education, and Welfare, 5600 Fishers Lane, Rockville, MD 20857, 301-443-5247.

SUPPLEMENTARY INFORMATION: Neese & Sons, Inc., filed a supplemental new animal drug application (NADA 102-717) providing for change of sponsor for a 10-gram-per-pound tylosin premix used for manufacture of complete swine feed.

On May 20, 1977, Neese & Sons, Inc., was purchased by Cargill, Inc. Under the Bureau of Veterinary Medicine's Supplemental Approval Policy, 42 FR 64367, approval of a supplemental NADA for intercorporate transfer of sponsorship does not require the reevaluation of the safety and effectiveness data in the parent NADA. Accordingly, this supplement is approved without any reevaluation of that data.

Therefore, under the Federal Food, Drug, and Cosmetic Act (sec. 512(i), 82 Stat. 347 (21 U.S.C. 360b(i))), and under authority delegated to the Commissioner of Food and Drugs (21 CFR 5.1), and redelegated to the Director of the Bureau of Veterinary Medicine (21 CFR 5.83), Parts 510 and 558 are amended as follows:

PART 510—NEW ANIMAL DRUGS

1. In Part 510, § 510.600 is amended in paragraph (c)(1) by deleting the entry for "Neese & Sons, Inc.," and by adding alphabetically a new sponsor entry, and in paragraph (c)(2) by deleting the entry for "024761" and by adding a new sponsor entry numerically, to read as follows:

§ 510.600 Names, addresses, and code numbers of sponsors of approved applications.

* * * * *

(c) * * *

(1) * * *

Firm name and address	Drug listing No.
* * * * *	
Cargill, Inc.-Nutrena Feed Div., P.O. Box 9300, Minneapolis, MN 55440	039502
* * * * *	

(2) * * *

Drug listing No.	Firm name and address
* * * * *	
039502	Cargill, Inc.-Nutrena Feed Div., P.O. Box 9300, Minneapolis, MN 55440.
* * * * *	

PART 558—NEW ANIMAL DRUGS FOR USE IN ANIMAL FEEDS

2. In Part 558, § 558.625 *Tylosin* is amended in paragraph (b)(47) by deleting the number "024761" and inserting in its place "039502."

Effective date. This amendment is effective October 5, 1979.

(Sec. 512(i), 82 Stat. 347 (21 U.S.C. 360b(i)).)

Dated September 27, 1979.

Lester M. Crawford,

Veterinary Medicine.

[FR Doc. 79-30927 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-03-M

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Parts 1 and 7

[T.D. 7646]

Income Tax; Taxable Years Beginning After December 31, 1953; and Temporary Income Tax Regulations Under the Tax Reform Act of 1976; Requirements Relating to Certain Exchanges Involving a Foreign Corporation

AGENCY: Internal Revenue Service, Treasury.

ACTION: Temporary regulations with request for comments.

SUMMARY: This document contains examples illustrating the application of previously published proposed and temporary regulations relating to the extent to which a foreign corporation shall be considered to be a corporation in connection with certain exchanges.

DATE: Written comments and requests for a public hearing must be delivered or mailed on or before December 4, 1979. The regulations apply to exchanges beginning after December 31, 1977.

FOR FURTHER INFORMATION CONTACT: Daniel Horowitz of the Legislation and Regulations Division, Office of the Chief Counsel, Internal Revenue Service, 1111 Constitution Avenue, NW., Washington, D.C. 20224, Attention: CC:LR:T, 202-566-3289, not a toll-free call.

SUPPLEMENTARY INFORMATION:

Background

This document contains proposed and temporary income tax regulations under section 367(b) of the Internal Revenue Code of 1954 as amended by section 1042(a) of the Tax Reform Act of 1976. These regulations consist entirely of examples illustrating the application of proposed and temporary regulations under this section of the Code which were published on December 30, 1977 (42 FR 65204, 65152). They are issued under the authority contained in sections 367(b) and 7805 of the Internal Revenue Code of 1954 (90 Stat. 1634 and 68A Stat. 917; 26 U.S.C. 367(b) and 7805).

Comments and Requests for a Public Hearing

Before adopting the proposed regulations contained in this document and those contained in the related notice of proposed rulemaking published in the Federal Register for Friday, December 30, 1977 (42 FR 65152 and 65204), consideration will be given to any written comments that are submitted (preferably six copies) to the Commissioner of Internal Revenue. All comments will be available for public inspection and copying. A public hearing will be held upon written request to the Commissioner by any person who has submitted written comments. If a public hearing is held, notice of the time and place will be published in the Federal Register.

Drafting Information

The principal author of these examples is Daniel Horowitz of the Legislation and Regulations Division of the Office of Chief Counsel, Internal Revenue Service. However, personnel from other offices of the Internal Revenue Service and Treasury Department participated in developing the regulation, both on matters of substance and style.

Adoption of Regulations

Part 7 of title 26 of the Code of Federal Regulations is amended by adding a new § 7.367(b)-13 to read as follows:

§ 7.367 (b)-13 Examples.

The following examples illustrate the application of §§ 7.367(b)-1 through 7.367(b)-12, inclusive. Unless otherwise indicated, no foreign corporation in any of these examples is a person referred to in section 6012.

Example (1). F, F1, and F2 are foreign corporations that were organized on January 1, 1960. At all times since this date, A, a domestic corporation, has owned 100 percent of the outstanding stock in F, F has owned 100 percent of the outstanding stock in F1, and F1 has owned 100 percent of the outstanding stock in F2. A, F, F1, and F2 each uses the calendar year as its taxable year. For each taxable year since their date of organization, F, F1, and F2 each has earnings and profits of $1,000. None of these earnings and profits is of a character described in section 1248(d). On January 1, 1980, F1 is liquidated into F in an exchange to which section 332 would apply if the status of F and F1 as corporations is recognized. A complies with the reporting requirements of § 7.367(b)-1(c) (with respect to the foreign personal holding company income realized by F on the liquidation).

Under § 7.367(b)-5(c), F and F1 are considered to be corporations for purposes of section 332 and other applicable sections. Under section 381(a)(1), F succeeds to F1's $20,000 of earnings and profits. These earnings and profits are considered to have been accumulated by F and retain their character as provided in § 7.367(b)-3(e) (*e.g.*, $3,000 retains its character as pre-1963 earnings and profits). F's basis in the stock in F2 received in the liquidating distribution is determined under section 334(b)(1).

Example (2). After the completion of the transaction in example (1), F has earnings and profits of $2,000 for its taxable year 1980, which, when added to the $20,000 of earnings and profits previously accumulated by F and the $20,000 of earnings and profits accumulated by F1 to which F succeeded under section 381(a)(1), gives a total of $42,000. F2 has earnings and profits of $1,000 for its taxable year 1980, giving F2 a total of $21,000 of earnings and profits. A's basis in its stock in F is $25,000.

(a) On January 1, 1981, A sells all its stock in F to an unrelated person for $100,000 in a transaction to which section 1248(a) applies. A recognizes gain of $75,000 ($100,000−$25,000) on this sale.

As provided in § 7.367(b)-12(e)(1), the rules of section 1248 apply in determining the portion of gain recognized by A that must be treated as a dividend. Under section 1248 and the regulations thereunder, the gain recognized by A must be treated as a dividend to the extent of the earnings and profits of F and F2 attributable to A's stock in F which were accumulated in taxable years beginning after December 31, 1962. The earnings and profits of F1 to which F succeeded under section 381(a)(1) by reason of the transaction in example (1) are considered to have been accumulated by F under § 7.367(b)-3(e). The earnings and profits of F1 accumulated in taxable years beginning before January 1, 1963, retain their character as pre-1963 earnings in the hands of F. Thus, the earnings and profits attributable to A's stock in F (the "section 1248 amount") total $54,000. This total consists of $19,000 actually accumulated during taxable years of F ($22,000−$3,000 of pre-1963 earnings and profits), $18,000 actually accumulated during taxable years of F2 ($21,000−$3,000 of pre-1963 earnings and profits) and $17,000 of the earnings and profits of F1 to which F succeeded under section 381(a)(1) by reason of the transaction in example (1) ($20,000−$3,000 of pre-1963 earnings and profits). For its taxable year 1981, A must include in its gross income $54,000 as a dividend and $21,000 ($75,000 gain−$54,000) as capital gain.

(b) On January 1, 1981, instead of A selling the stock of F as in example (2)(a), F is liquidated into A in an exchange to which section 332 would apply if the status of F as a corporation is recognized. F's basis in its assets is $20,000.

The all earnings and profits amount of A with respect to F is $42,000. This amount includes $20,000 of the earnings and profits of F1 to which F succeeded under section 381(a)(1) by reason of the transaction in example (1) since, under § 7.367(b)-3(e), the $20,000 is considered as if accumulated by F. It also includes the $22,000 actually accumulated during taxable years of F. As provided in § 7.367(b)-2(f) and (h)(1), however, it does not include the $21,000 of earnings and profits of F2. A complies with the reporting requirements of § 7.367(b)-1 (c).

(i) A includes in gross income for its taxable year 1981 the all earnings and profits amount of $42,000.

The $42,000 included in income is considered to be a dividend as provided in § 7.367(b)-3(b). This amount increases the earnings and profits of A and decreases the earnings and profits of F to zero. Under § 7.367(b)-5(b), F is considered to be a corporation. A's basis in F's assets, determined under section 334(b)(1), is $20,000.

(ii) A does not include the all earnings and profits amount in gross income for its taxable year 1981.

Under § 7.367(b)-5(b), solely for the purpose of determining the extent to which gain is recognized on the exchange, F is not considered to be a corporation, and A must include in gross income $75,000 ($100,000 fair market value of assets received−$25,000 basis in the stock in F). For all other purposes, F is a corporation. Thus, section 1248 applies to A's exchange of its stock in F and $54,000 is included in A's gross income as a dividend and $21,000 is included as capital gain. See example (2)(a). A succeeds to F's earnings and profits under section 381(a)(1). Pursuant to § 7.367(b)-5(b), A's basis in F's assets is $20,000 under section 334(b)(1).

(iii) A makes a computational error in determining the all earnings and profits amount to include in gross income for its taxable year 1981. If A demonstrates that the error was made in good faith and agrees to correct the error, the Commissioner shall conclude under § 7.367(b)-1(b)(2) that F will be considered to be a corporation for purposes of applying section 332.

(c) The facts are the same as in example (2)(b) except that F is a corporation organized under the laws of Puerto Rico, which in all relevant years has met the requirements of section 957(c) or would have met such requirements if the Revenue Act of 1962 had been in effect. Neither F1 nor F2 meets or has ever met the requirements of section 957(c). Of the $4,000 in earnings accumulated by F after December 31, 1977, $450 would not have qualified for the credit of section 936(a) had F been a domestic corporation which met the requirements of section 936(a)(1) and which had elected the credit under that section.

The all earnings and profits amount of A with respect to F is $20,450. This amount includes the $20,000 of earnings and profits to which F succeeded under section 381(a)(1) upon the liquidation of F1. See example (2)(b). This $20,000 retains its character as earnings and profits which do not meet the requirements of section 957(c). Under § 7.367(b)-2(j), the all earnings and profits amount also includes the $450 of earnings and profits accumulated by F, after December 31, 1977, which would not have qualified for the credit of section 936(a).

(i) A includes in gross income for its taxable year 1981, the all earnings and profits amount of $20,450 pursuant to the liquidation of F on January 1, 1981.

The $20,450 included in income is considered to be a dividend as provided in § 7.367(b)-3(b). This amount increases the earnings and profits of A and decreases the earnings and profits of F. A succeeds under section 381(a)(1) to the remaining $21,550 ($22,000+$20,000−$20,450) of F's earnings and profits. A's basis in F's assets, determined under section 334(b)(1), is $20,000.

(ii) A does not include the all earnings and profits amount in gross income for its taxable year 1981.

Under § 7.367(b)-5(b), solely for the purpose of determining the extent to which gain is recognized on the exchange pursuant to the liquidation of F on January 1, 1981, F is not considered to be a corporation. Thus, A must include in its gross income $75,000 ($100,000 fair market of assets received−$25,000 basis in the stock in F). Section 1248(a) does not apply because F never has been a controlled foreign corporation. See section 957(c). Thus, the entire $75,000 is capital gain. The other consequences of A's election not to include the all earnings and profits amount in gross income are the same as those illustrated in example (2)(b)(ii).

(d) The facts are the same as in example (2)(b) except that, of the $22,000 of earnings and profits actually accumulated during taxable years of F, the $16,000 accumulated in taxable years beginning before January 1, 1976, is of a character described in section 1248(d)(3).

As explained in example (2)(b), the all earnings and profits amount of A with respect to F is $42,000. This amount is not reduced by the $16,000 of earnings and profits of F which are of a character described in section 1248(d)(3). See § 7.367(b)-3(c)(1)(ii). Pursuant to the liquidation of F on January 1, 1981, A includes $42,000 in gross income as provided in § 7.367(b)-5(b). In the notice required under § 7.367(b)-1(c), A elects to treat the $16,000 of earnings and profits of a character described in section 1248(d)(3) as capital gain. See § 7.367(b)-3(d). Thus, of the $42,000, $26,000 is considered to be a dividend under § 7.367(b)-3(b), and the remaining $16,000 is considered to be capital gain.

Example (3). On July 1, 1980, A, a domestic corporation, purchased all the outstanding stock of F, a foreign corporation, from B, an unrelated person, for $5,000. At all times since this date, A has owned all of the outstanding stock in F. A and F each uses the calendar year as its taxable year. On January 1, 1982, F is liquidated into A pursuant to a plan of liquidation adopted on July 15, 1980, in an exchange to which section 332 would apply if the status of F as a corporation is recognized. A complies with the reporting requirements of § 7.367(b)-1(c). On the date of the liquidation, F's assets have an aggregate fair market value of $6,000. No distributions were made with respect to A's stock in F during the period from July 1, 1980, to and including January 1, 1982. A's all earnings and profits amount under § 7.367(b)-2(f) with respect to F is $150, the earnings and profits accumulated by F during this period. None of the these earnings and profits is of a character described in section 1248(d).

(a) A includes in gross income for its taxable year 1982 the all earnings and profits amount of $150.

The $150 included in income is considered to be a dividend as provided in § 7.367(b)-3(b). This amount increases the earnings and profits of A and decreases the earnings and profits of F. Under § 7.367(b)-5(b), F is considered to be a corporation. A's basis in F's assets is determined under section 334(b)(2) and § 1.334-1(c). Thus, A's basis in F's assets is determined by allocating $5,150 (A's basis of $5,000 in the F stock increased, as provided in § 1.334-1(c)(4)(v)(*a*)(2), by F's earnings and profits of $150 for the period between July 1, 1980 and January 1, 1982) among the assets distributed as provided in § 1.334-1(c).

(b) A does not include the all earnings and profits amount in gross income for its taxable year 1982.

Under § 7.367(b)-5(b), solely for the purpose of determining the extent to which gain is recognized on the exchange, F is not considered to be a corporation, and A must include in gross income $1,000 ($6,000 fair market value of assets received—$5,000 basis in the stock in F). For all other purposes, F is a corporation. Thus, section 1248 applies to A's exchange of its stock in F and $150 (the earnings and profits attributable to A's stock in F) is included in A's gross income as a dividend, and $850 ($1,000—$150) is included as capital gain. Pursuant to § 7.367(b)-5(b), A's basis in F's assets is determined under section 334(b)(2) and § 1.334-1(c). Thus, the basis of these assets will be determined by allocating $5,150 among these assets in the manner described in example (3)(a).

Example (4). F is a foreign investment company (as defined in section 1246(b)) that was organized on January 1, 1960, and uses the calendar year as its taxable year. A, a domestic corporation, has owned all the outstanding stock of F since F's organization. For each of its taxable years, F has $100 of earnings and profits. A's basis in its stock in F is $200. F's basis in its assets is $250.

(a) On January 1, 1980, foreign corporation X, which is not an "investment company" within the meaning of section 368(a)(2)(F)(iii), acquires all of A's stock in F. In exchange for this stock, A receives 10 percent of the voting stock in X having a fair market value of $5,000. Section 354 would apply to the exchange of stock by A, and the transaction would qualify as a reorganization described in section 368(a)(1)(B), if the status of F and X as corporations is recognized. A complies with the reporting requirements of § 7.367(b)-1 (c).

Section 7.367(b)-6 does not apply to the exchange because X is a foreign corporation. Section 7.367(b)-7 does not apply because F is a foreign investment company. F and X are considered to be corporations and A does not recognize the gain of $4,800 ($5,000 fair market value of X stock received—$200 basis in F stock exchanged) realized on the exchange. A's stock in X is treated as stock of a foreign investment company held by A throughout the period that A held stock in F. See section 1246(c). A's basis in the stock in X and X's basis in the stock in F are each $200 under sections 358 and 362, respectively.

(b) The facts are the same as in example (4)(a), except that X is a domestic corporation.

A's section 1246 amount with respect to F is $1,700. As provided in section 1246 and §7.367(b)-2(c), this amount takes into account only the earnings and profits of F accumulated in its 17 taxable years beginning after December 31, 1962. Pursuant to the exchange on January 1, 1980, of A's stock in F for stock in X, A, as provided in § 7.367(b)-6(b), includes the Section 1246 amount of $1,700 in gross income for its taxable year 1980 as gain from the sale of an asset which is not a capital asset under § 7.367(b)-3(a)(1). This amount increases the earnings and profits of A but does not decrease the earnings and profits of F. F is considered to be a corporation. As provided in § 7.367(b)-6(d), the $1,700 is treated as gain recognized for purposes of applying sections 358 and 362. Thus, A's basis in the stock in X received in the exchange, as determined under section 358, is $1,900 (A's basis of $200 in the stock in F increased by its $1,700 gain). X's basis in the stock in F acquired in the exchange, as determined under section 362, is $1,900 (the $200 basis of the stock in F in the hands of A increased by A's $1,700 gain).

(c) The facts are the same as in example (4)(b), except that on January 1, 1980, A receives the stock in X (a domestic corporation) pursuant to the acquisition by X of all of F's assets and the liquidation of F, rather than pursuant to the acquisition by X of all of A's stock in F. Section 354 would apply to the exchange of stock in F by A pursuant to the liquidation of F, and the transaction would qualify as a reorganization described in section 368(a)(1)(C), if the status of F as a corporation is recognized. A's all earnings and profits amount with respect to its stock in F, determined under § 7.367(b)-2(f), is $2,000 ($100 × 20 years beginning with January 1, 1960, the date of organization of F).

(i) Pursuant to § 7.367(b)-6(c)(1), A includes the all earnings and profits amount of $2,000 in gross income for its taxable year 1980.

As provided in § 7.367(b)-3(a), the $1,700 of earnings and profits accumulated in taxable years beginning after December 31, 1962, is included in income as gain from the sale of an asset which is not a capital asset, and the $300 of earnings and profits accumulated in taxable years beginning before January 1, 1963, is included in income as a dividend. These amounts increase the earnings and profits of A but do not decrease the earnings and profits of F. F is considered to be a corporation. A's basis in the stock in X received in the exchange, determined under section 358, is $2,200 (A's basis of $200 in the F stock increased by the $1,700 gain, under § 7.367(b)-6(d), and by the $300 included in income as a dividend, under section 358(a)(1). X's basis in the assets of F acquired in the exchange, determined under section 362, is $250 (F's basis in those assets), since no gain was recognized to F, the transferor. X succeeds to F's earnings and profits under section 381(a)(2).

(ii) A does not include the all earnings and profits amount in gross income as required by § 7.367(b)-6(c)(1).

Under § 7.367(b)-6(c)(2), solely for the purpose of determining the extent to which gain is recognized on the exchange, F is not considered to be a corporation and A must recognize gain of $4,800 ($5,000 fair market value of X stock received—$200 basis in F stock exchanged). For all other purposes, F is a corporation. Thus, section 1246 applies to A's exchange of its stock in F and $1,700 (the section 1246 amount) is included in A's gross income as ordinary income and $3,100 is included as capital gain. As provided in § 7.367(b)-6(c)(2), A's basis in the stock in X received is $200, determined under section 358. X's basis in the assets of F which were acquired is $250, determined under section 362. X succeeds to F's earnings and profits under section 381(a)(2).

Example (5). F, F1, and F2 are foreign corporations that were organized on January 1, 1960. At all times since this date, A, a domestic corporation, has owned 60 percent of the outstanding stock of F, and X, a foreign corporation which is unrelated to A and not subject to tax under subtitle A of the Code, has owned 40 percent of the outstanding stock of F. At all times since this date, F has owned 100 percent of the outstanding stock in F1, and F1 has owned 100 percent of the outstanding stock in F2. A, F, F1, and F2 each uses the calendar year as its taxable year.

(a) For each taxable year since their date of organization, F, F1, and F2 each has earnings and profits of $100. For each taxable year beginning with 1963, F has $40 of subpart F income. For each such taxable year, A includes in its income $24 ($40 × 60 percent of the stock in F) by reason of section 951(a)(1)(A). For each of these years, $24 of F's earnings and profits are attributable to amounts thus included in income by A and therefore are of a character described in section 1248(d)(1). None of the earnings and profits of F1 or F2 is of a character described in section 1248(d). A's basis in its stock in F was $324 on January 1, 1960. As of January 1, 1980, A has included $408 ($24 × 17 years beginning with 1963) in gross income as subpart F income. Thus, under section 961(a), A's basis in its stock in F is $732 ($324 + $408) on that date. F's basis in its assets is $250.

On January 1, 1980, foreign corporation Y acquires all the assets of F in return for Y's voting stock. A and X exchange all their stock in F for stock in Y, and F is liquidated. The Y stock received by A has a fair market value of $6,000 so that A realizes gain of $5,268 ($6,000-$732 basis in the F stock exchanged). Section 354 would apply to the exchange of the stock in F by A, and the transaction would qualify as a reorganization described in section 368(a)(1)(C), if the status of F and Y as corporations is recognized.

(i) In the exchange on January 1, 1980, by A of its stock in F, A receives 20 percent of the voting stock in Y. After the exchange Y is a controlled foreign corporation. Since A is a United States shareholder of Y under § 7.367(b)-2(b), the attribution rules of § 7.367(b)-9 apply, as provided in § 7.367(b)-7(b). A's section 1248 amount with respect to F is $3,060. This amount, determined as provided in § 7.367(b)-2 (d) and (i), consists of $1,020 ($100 × 17 years beginning with 1963 × 60 percent of the F stock) of earnings and profits of F, F1, and F2, respectively. Of the $1,020 of earnings and profits of F, $408 ($24 × 17 years beginning with 1963) is of a character described in section 1248(d)(1). A's all earnings and profits amount with respect to F, determined as provided in § 7.367(b)-2(f) and (h)(1), is $1,200 ($100 × 20 years beginning with 1960 × 60 percent of the F stock). A's additional earnings and profits amount with respect to F is $180 ($100 × 3 years ending with 1962 × 60 percent of the F stock).

Under § 7.367(b)-9(b)(1), A's section 1248 amount, A's all earnings and profits amount, and A's additional earnings and profits amount are attributed to the stock in Y which A receives in the exchange. Under § 7.367(b)-9(b)(2) and § 7.367(b)-9(c), the earnings and profits of Y are increased by $6,000 ($2,000 of earnings and profits of F, F1, and F2, respectively). Under § 7.367(b)-9(b)(3) and (d), the earnings and profits of F, F1, and F2, respectively, are reduced by $2,000. A complies with the reporting requirements of § 7.367(b)-1(c), and Y, F, F1, and F2 comply with the recordkeeping requirements of § 7.367(b)-1(d). F and Y are considered to be corporations and section 354 applies to the exchange of the stock in F by A.

In the notice required under § 7.367(b)-1(c), A makes the consent dividend election provided for in § 7.367(b)-9(f)(1). Thus, the $1,700 of post-1962 earnings and profits of F2 is treated as if, immediately prior to the reorganization, it had been distributed as a dividend through F1 to F. The $1,700 of post-1962 earnings and profits of F1 is treated as if, immediately prior to the reorganization, it had been distributed as a dividend to F. These earnings and profits treated as if distributed must be included in A's gross income to the extent, if any, required under section 551 or 951. If A includes under section 951 its full pro-rata share of the amount treated as distributed, the amount attributed to A's stock in Y which is of a character described in section 1248(d)(1) will be $2,448 ($3,400 × 60 percent of the F stock + $408 of F's earnings and profits which otherwise are of a character described in section 1248(d)(1)).

A's basis in its stock in F immediately prior to the reorganization is increased under section 961(a) by $2,040 from $732 to $2,772. Thus, A's basis in the Y stock received, determined under section 358, is $2,772. In addition, under § 7.367(b)-9(e)(1), the basis of Y's stock in F1 is increased by $4,000 ($600 of pre-1963 earnings and profits + 3,400 of post-1962 earnings and profits), and the basis of F1's stock in F2 is increased by $2,000 ($300 of pre-1963 earnings and profits +$1,700 of post-1962 earnings and profits). However, the increases in respect of pre-1963 earnings and profits are made only for purposes of computing the all earnings and profits amount and the additional earnings and profits amount with respect to subsequent transactions. See § 7.367(b)-9(e)(3).

(ii) In the exchange on January 1, 1980, by A of its stock in F, A receives 5 percent of the voting stock in Y (rather than 20 percent as in example (5)(a)(i)).

Since A is not a United States shareholder of Y as defined in § 7.367(b)-2(b) immediately after the exchange, § 7.367(b)-7(c)(1)(i) applies. A complies with the reporting requirements of § 7.367(b)-1(c). As required by § 7.367(b)-7(c)(1)(i), A includes in gross income for its taxable year 1980 $2,652, which is the section 1248 amount of $3,060 (computed as in example (5)(a)(i)) reduced, as provided in § 7.367(b)-3(c)(1), by the $408 of earnings and profits of F retaining their character as earnings and profits described in section 1248(d)(1). F and Y are considered to be corporations for purposes of applying section 354 to the exchange of the stock in F by A. Accordingly, no gain is recognized by A. Y succeeds to the $2,000 of earnings and profits of F under section 381(a)(2). In addition, A's basis in the stock in Y received in the exchange, determined under section 358, is $3,384 ($732 basis in F stock exchanged + $2,652 included in gross income in the manner provided in section 961). See § 7.367(b)-12(d). Y's basis in the assets of F, determined under section 362, is $250 (F's basis in those assets), since no gain was recognized to F.

Under § 7.367(b)-3 (b) and (f), the foreign tax credit provisions (sections 78 and 901 through 908) apply as if the $2,652 included in gross income by A were actually distributed to A as a dividend immediately before the exchange. A will be deemed to have paid the proportion of the foreign taxes paid or deemed paid by F, F1, and F2, determined as provided in section 902 and the regulations thereunder. For this purpose, the portions of the section 1248 amount included in gross income by A which are attributable, respectively, to F, F1, and F2 are determined as provided in § 7.367(b)-3(g)(1). Thus, $612 ($612 × $2,652/$2,652) is attributable to F and $1,020 ($1,020 × $2,652/$2,652) is attributable to F1 and F2, respectively. (The first factor in the numerator is the section 1248 amount determined as if the corporation in question were the only corporation, and reduced under § 7.367(b)-3(c)(1)(i) by the amount of earnings and profits retaining its character as earnings and profits described in section 1248(d)(1). The second factor in the numerator is the amount included in A's gross income as a dividend. The denominator is the section 1248 amount reduced under § 7.367(b)-3(c)(1)(i) by the amount of earnings and profits retaining its character as earnings and profits described in section 1248(d)(1).) As provided in § 7.367(b)-3(g)(2), the amounts thus determined to be attributable to F1 and F2 are treated as if distributed directly to A by F1 and F2, respectively, for purposes of applying section 902. These amounts increase the earnings and profits of A but do not decrease the earnings and profits of F, F1, or F2.

(b) The facts are the same as in example (5)(a)(ii) except that A's basis in its F stock was $3,824 on January 1, 1960 (rather than $324) and, by reason of section 961(a), is $4,232 ($3,824+$408 earnings and profits of F previously included in A's gross income under section 951(a)(1)(A)) on January 1, 1980. On the exchange on January 1, 1980 of its stock in F for 5 percent of the voting stock in Y, A realizes a gain of $1,768 ($6,000 fair market value of the Y stock received −$4,232 basis in the F stock exchanged).

As required by §§ 7.367(b)-3(c)(1)(i) and 7.367(b)-7(c)(1)(i), A includes in gross income as a dividend the realized gain of $1,768 since that amount is less than $2,652 ($3,060 section 1248 amount−$408 of earnings and profits of F retaining their character as earnings and profits described in section 1248(d)(1)). For the purpose of determining the proportion of the foreign taxes paid or deemed paid by F, F1, and F2 which A will be deemed to have paid under section 902 and the regulations thereunder, the portions of the amount included in gross income by A which are attributable, respectively, to F, F1, and F2 are determined as provided in § 7.367(b)-3(g)(1). Thus, $408 ($612 × $1,768/$2,652) is attributable to F and $680 ($1,020 × $1,768/$2,652) is attributable to F1 and F2, respectively.

(c) The facts are the same as in example (5)(b), except that, since January 1, 1963, F1 has earnings and profits of $100 for each of five taxable years and deficits of ($100) for each of the other twelve taxable years, and F2 has deficits of ($100) for each of four taxable years and earnings and profits of $100 for each of the other thirteen taxable years (rather than F1 and F2 having earnings and profits of $100 for each taxable year). On the exchange, on January 1, 1980, of its stock in F for 5 percent of the voting stock in Y, A realizes a gain of $1,768 ($6,000−$4,232) as in example (5)(b). A's section 1248 amount with respect to F is $1,140. This amount, determined as provided in § 7.367(b)-2(d) and (i), consists of $1,020 of earnings and profits of F ($100 × 17 years beginning with 1963 × 60 percent of the F stock), ($420) of deficit of F1 ($100 × 5 profitable years × 60 percent × 100 percent of the F1 stock−($100) × 12 deficit years × 60 percent × 100 percent), and $540 of earnings and profits of F2 ($100 × 13 profitable years × 60 percent × 100 percent × 100 percent of the F2 stock—($100) X 4 deficit years X 60 percent X 100 percent X 100 percent).

As required by §§ 7.367(b)-3(c)(1)(i) and 7.367(b)-7(c)(1)(i), A includes in gross income as a dividend, $732 ($1,140 section 1248 amout−$408 of earnings and profits retaining its character as earnings and profits described in section 1248(d)(1)). For the purpose of determining the proportion of the foreign taxes paid or deemed paid by F, F1, and F2 which A will be deemed to have paid under section 902 and the regulations thereunder, the portions of the amount included in gross income by A which are attributable respectively to F, F1, and F2 are determined as provided in § 7.367(b)-3(g)(1). (Deficits are disregarded in computing the first factor in the numerator of each fraction. They are not, however, disregarded for any other purpose.) Thus, $612 ($612 × $732/$732) is attributable to F, $500 ($500 × $732/$732) is attributable to F1, and $1,300 ($1,300 × $732/$732) is attributable to F2.

Example (6). On January 1, 1981, one year after the transaction described in example

(5)(a)(ii), Y makes a pro-rata distribution of $10,000 with respect to its stock. As of January 1, 1981, Y has $10,000 of earnings and profits, including the $2,000 of F's earnings and profits to which Y succeeded under section 381(a)(2) pursuant to the earlier transaction. None of the $8,000 of earnings and profits actually accumulated by Y is of a character described in section 1248(d). A, which owns the 5 percent of the Y voting stock received in the earlier transaction, receives $500 as its pro-rata share of the distribution from Y.

As provided in § 7.367(b)-12(d), the $2,652 that was included in gross income by A under § 7.367(b)-7 pursuant to the earlier transaction is treated in the same manner as amounts previously included in A's gross income under section 951. By virtue of succeeding to F's earnings and profits, Y has $1,020 of earnings and profits which have previously been included in A's gross income. This amount consists of the $408 of F's subpart F income and the $612 of the section 1248 amount attributable to F which was included in A's gross income pursuant to the earlier transaction. Under § 7.367(b)-12(d)(1), the $500 distributed by Y to A shall be excluded from A's gross income in the same manner as under section 959. A's basis in its stock in Y shall be decreased by $500 in the manner provided in section 961 (b) from $3,384 to $2,884. After the distribution, Y has $520 ($1,020−$500) of earnings and profits which have previously been included in A's gross income. (F1 and F2 each has $1,020 of such earnings and profits.)

Example (7). On January 1, 1981, one year after the transaction described in example (5)(a)(i), Y makes a pro-rata distribution of $10,000 with respect to its stock. As of January 1, 1981, Y has $10,000 of earnings and profits. This amount consists of the $6,000 of earnings and profits of F, F1, and F2 by which the earnings and profits of Y were increased under § 7.367(b)-9 (b)(2) and (c) pursuant to the earlier transaction, $1,000 actually accumulated by Y after the earlier transaction (in its taxable year 1980), and $3,000 actually accumulated by Y before the earlier transaction. None of the $4,000 of earnings and profits actually accumulated by Y is of a character described in section 1248(d). Pursuant to the earlier transaction, A's section 1248 amount of $3,060, A's all earnings and profits amount of $1,200, and A's additional earnings and profits amount of $180 have been attributed to A's stock in Y under § 7.367(b)-9(b)(1). Of the $3,060 section 1248 amount so attributed, $408 of the earnings and profits from F (A's pro-rata share of the subpart F income actually derived by F), and $1,020 of the earnings and profits from F1 and F2, respectively (pursuant to the § 7.367(b)-9(f)(1) consent dividend election), are of a character described in section 1248(d)(1).

Since the amount of the distribution does not exceed Y's earnings and profits (including the earnings and profits of F, F1, and F2 by which the earnings and profits of Y were increased), the entire distribution is a dividend except to the extent provided in § 7.367(b)-12. A, which owns 20 percent of the Y voting stock received in the earlier transaction, receives $2,000 as its pro-rata share of the distribution from Y. Under § 7.367(b)-12(c), this distribution is considered to be made first out of $200 of the $1,000 of earnings and profits accumulated by Y since the attribution pursuant to the earlier transaction and is a dividend to A. The remaining $1,800 is considered to be made out of the earnings and profits attributed to A's stock in Y. Under § 7.367(b)-12(c)(3), $600 of this $1,800 is considered as if distributed from the earnings and profits of F, F1, and F2, respectively ($1,800 × $1,020 of section 1248 amount attributed from each corporation/ $3,060 section 1248 amount attributed to A's stock in Y). These amounts retain their character as amounts described in section 1248(d)(1). Since $408 of the earnings and profits attributed from F, and all $1,020 of the earnings and profits attributed from F1 and F2, respectively, are of such a character, only $192 [($600−$408) + ($600−$600) + ($600−$600)] of the $1,800 distributed out of attributed earnings and profits is considered to be a dividend. the $1,608 ($408 + $600 + $600) distribution of earnings and profits of a character described in section 1248(d)(1), which otherwise would be treated as a dividend, is excluded from gross income under section 959. Thus, $392 of the $2,000 distributed to A is considered to be a dividend, of which $200 is from earnings and profits of Y for its taxable year 1980 and $192 is from earnings and profits accumulated by F prior to its acquisition by Y.

A's basis in its stock in Y is reduced, under section 961(b), by the $1,608 excluded from gross income under section 959(a) from $2,772 to $1,164. A's section 1248 amount attributed to its stock in Y is reduced, under § 7.367(b)-12(c)(2), by $1,800 from $3,060 to $1,260, of which $840 [($1,020−$600) + ($1,020−$600)] is of a character described in section 1248(d)(1). A's all earnings and profits amount is reduced from $1,200 to $600, none of which is of a character described in section 1248(d)(1). A's additional earnings and profits amount is not affected by the distribution. See section 316.

Example (8). On January 1, 1982, 2 years after the transaction described in example (5)(a)(i), and 1 year after the distribution described in example (7), A sells all its stock in Y for $7,000 realizing a gain of $5,836 ($7,000−$1,164). During 1981, Y had $1,000 of earnings and profits. Under § 7.367(b)-12(e), the section 1248 amount attributable to A's stock in Y is $1,460. This amount consists of $200 of the $1,000 of Y's earnings and profits for 1981 (A owns 20 percent of the stock in Y), plus the $3,060 section 1248 amount attributed to A's stock in Y, reduced as provided in § 7.367(b)-12(e)(2)(ii) by the $1,800 considered distributed in example (7) out of the section 1248 amount so attributed. (See § 7.367(b)-12(c)(2).) Of this section 1248 amount of $1,460, the $840 [($1,020−$600) + ($1,020−$600)] of the earnings and profits attributed from F1 and F2 that remain after the distribution described in example (7) are of a character described in section 1248(d)(1). Thus, $620 ($1,460 Section 1248 amount −$840 section 1248(d)(1) earnings and profits) of the gain on the sale of the Y stock is treated as a dividend under section 1248(a) and the remaining $5,216 ($5,836−$620) is recognized as capital gain.

Example (9). F, F1, F2, and F3 are foreign corporations that were organized on January 1, 1975. At all times since this date, A, a domestic corporation, has owned 60 percent of the outstanding stock in F, and X, a foreign corporation unrelated to A and not subject to tax under subtitle A of the Code, has owned 40 percent of the outstanding stock in F. At all times since this date, F has owned 100 percent of the outstanding stock in F1, F1 has owned 100 percent of the outstanding stock in F2, and F2 has owned 100 percent of the outstanding stock in F3. A, F, F1, F2, and F3 each uses the calendar year as its taxable year. For each taxable year since their date of organization, F, F1, and F3 each has earnings and profits of $100. For each taxable year since its date of organization, F2 has a deficit of ($100). None of the earnings and profits of F, F1, or F3 is of a character described in section 1248(d). A's basis in its stock in F is $620.

On January 1, 1980, A and X exchange all of their stock in F. As sole consideration for the stock exchanged, A receives 20 percent of the voting stock in foreign corporation Y, and X receives 13.3 percent of the voting stock in Y. The Y stock received by A has a fair market value of $4,000. Section 354 would apply to the exchange of stock in F by A, and the transaction would qualify as a reorganization described in section 368(a)(1)(B), if the status of F and Y as corporations is recognized. After the transaction, Y is a controlled foreign corporation but is not a foreign personal holding company.

A realizes gain of $3,380 ($4,000 fair market value of the Y stock received—$620 basis in the F stock exchanged). Since A owns 20 percent of the voting stock in Y immediately after the exchange, A is a United States shareholder of Y as defined in § 7.367(b)-2(b). Accordingly, the attribution rules of § 7.367(b)-9 apply, as provided in § 7.367(b)-7(b)(1). Under § 7.367(b)-9(b)(1), A's section 1248 amount of $600 is attributed to the stock in Y which A received in the exchange. This amount consists of $300 of earnings and profits of F, F1, and F3, respectively ($100×5 years×60 percent of the stock in F), and ($300) of deficit of F2 (($100)×5 years×60 percent). Under § 7.367(b)-9(b)(2) and § 7.367(b)-9(c), the earnings and profits of Y are increased by $1,500 ($500 of earnings and profits of F, F1 and F3, respectively). Any deficit of Y is increased by the ($500) deficit of F2, subject to § 7.367(b)-11, relating to the manner in which such deficit may be used. These earnings and profits and deficit retain their character as provided in § 7.367(b)-3(e). Under § 7.367(b)-9(b)(3) and § 7.367(b)-9(d), the earnings and profits of F, F1, and F3, and the deficit of F2 are each correspondingly reduced by $500. A complies with the reporting requirements of § 7.367(b)-1(c), and Y, F, F1, F2, and F3 comply with the recordkeeping requirement of § 7.367(b)-1(d). F and Y are considered to be corporations and section 354 applies to the exchange of stock by A. A's basis in the stock in Y determined under section 358 is $620.

(a) In the notice required under § 7.367 (b)-1(c), A does not make the consent dividend election provided for § 7.367 (b)-9(f)(1).

Under § 7.367-9(e)(1), F1's basis in its stock in F2 and F's basis in its stock in F1 are each reduced by $500. These reductions are made on account of the $500 reduction in F2's deficit. Since A did not make the election under § 7.367(b)–9(f)(1), no basis adjustment on account of F1 and F3's earnings and profits is permitted under § 7.367(b)–9(e)(1). Under § 7.367(b)–9(e)(2), Y's basis in its stock in F is reduced by $500 on account of the $500 reduction F2's deficit. Since A did not make the election under § 7.367(b)–9(f)(1), no adjustment to Y's basis in F is permitted on account of earnings and profits accumulated in taxable years beginning after December 31, 1962, even if the election provided for in § 7.367(b)–9(f)(2)(ii) is made. See § 7.367(b)–9(f)(2). Thus, Y's basis in its F stock, determined under section 362 and § 7.367(b)–9(e), is $120 ($620–$500).

(b) The facts are the same as in example (9)(a), except that in the notice required under § 7.367(b)–1(c), A makes the consent dividend election provided for in § 7.367(b)–9(f)(1). In addition, all the United States shareholders of Y make a consent dividend election as provided in section 565 for 1980 (the taxable year in which the reorganization occurred). See § 7.367(b)–9(f)(2)(ii).

Under § 7.367(b)–9(f)(1), the $500 of earnings and profits of F3 is treated as if, immediately prior to the reorganization, it had been distributed as a dividend through F2 and F1 (unreduced by the deficit of F2) to F. The $500 of earnings and profits of F1 is treated as if, immediately prior to the reorganization, it had been distributed as a dividend to F. Accordingly, under § 7.367(b)–9(e)(1), F2's basis in the F3 stock is increased by $500; F1's basis in the F2 stock is decreased by the ($500) deficit from F2 (see example (9)(a)) and increased by the $500 of earnings and profits from F3 for a net adjustment of zero; and F's basis in the F1 stock is decreased by the ($500) deficit from F2 (see example (9)(a)) and increased by the $1,000 of earnings and profits from F3 and F1 for a net increase of $500. For the consequences to A of making the consent dividend election provided for in § 7.367(b)–9(f)(1), see example (5)(a).

Under § 7.367(b)–9(f)(2), the $500 of earnings and profits of F3 is treated as if, immediately after the reorganization, it had been distributed as a dividend through F2, F1 and F (unreduced by the deficit of F2) to Y. The $500 of earnings and profits of F1 is treated as if, immediately after the reorganization, it had been distributed as a dividend through F to Y. The $500 of earnings and profits of F is treated as if, immediately after the reorganization, it had been distributed as a dividend to Y. Accordingly, under § 7.367(b)–9(e)(2), Y's basis in the F stock is increased by the $1,500 total of the earnings and profits treated as if distributed to Y and is decreased by the ($500) deficit of F2 (see example (9)(a)). Thus, the net increase in Y's basis in the F stock is $1,000 and this basis, determined under section 362 and § 7.367(b)–9(e), is $1,620 ($620 + $1,000). For the consequences to the United States shareholders of Y of the consent dividend to Y, see sections 951 and 959.

Example (10). F, F1, and F2 are foreign corporations that were organized on January 1, 1975. At all times since this date, A, a domestic corporation, has owned 100 percent of the outstanding stock in F. F has owned 90 percent of the outstanding stock in F1. X, a foreign corporation unrelated to A and not subject to tax under subtitle A of the Code, has owned 10 percent of the outstanding stock in F1, and F1 has owned 100 percent of the outstanding stock in F2. F, F1, and F2 each uses the calendar year as its taxable year. For each taxable year since their date of organization, F, F1, and F2 each has earnings and profits of $100. None of the earnings and profits of F, F1, or F2 is of a character described in section 1248(d). F's basis in its stock in F1 is $620.

On January 1, 1980, F exchanges all of its stock in F1. X retains its stock in F1. As sole consideration for the stock exchanged, F receives 20 percent of the voting stock in foreign corporation Y. The Y stock received by F has a fair market value of $4,000. Section 354 would apply to the exchange of the stock in F1 by F, and the transaction would qualify as a reorganization described in section 368(a)(1)(B), if the status of F1 and Y as corporations is recognized. After the transaction Y is a controlled foreign corporation. Y uses the calendar year as its taxable year.

F realizes gain of $3,380 ($4,000 fair market value of the Y stock received—$620 basis in the F1 stock exchanged). Since A is a United States shareholder of Y after the exchange, the attribution rules of § 7.367(b)–9 apply, as provided in § 7.367(b)–7(b). Under § 7.367(b)–9(b)(1), A's section 1248(c)(2) amount of $900 is attributed to the stock in Y which F receives in the exchange. This amount consists of $450 ($100 × 5 years × 90 percent of the stock in F1) of the earnings and profits of F1 and F2, respectively. The earnings and profits of Y are increased by the $450 of earnings and profits of F1 and the $450 of earnings and profits of F2, in accordance with §§ 7.367(b)–9(b)(2) and 7.367(b)–9(c). The earnings and profits of F1 and F2, respectively, are correspondingly reduced by $450 under §§ 7.367(b)–9(b)(3) and 7.367(b)–9(d). In addition, under § 7.367(b)–9(c)(2), the $50 of earnings and profits of F1 and F2, respectively, which do not increase the earnings and profits of Y, is considered to be entirely attributable to the stock not acquired by Y (*i.e.*, the stock owned by X). A complies with the reporting requirements of § 7.367(b)–1(c), and Y, F, F1, and F2 comply with the recordkeeping requirements of § 7.367(b)–1(d). F1 and Y are considered to be corporations and section 354 applies to the exchange of F1 stock by F.

In the notice required in § 7.367(b)–1(c), A does not make the consent dividend election provided for in § 7.367(b)–9(f)(1). Accordingly, no adjustment to basis is made under § 7.367(b)–9(e).

Example (11). On January 1, 1981, after the transaction described in example (10), A sells all its stock in F. In taxable year 1980, Y, F, F1, and F2 each has $100 of earnings and profits. Upon A's sale of its stock in F, A's section 1248 amount is $1,556. This amount consists of $600 of earnings and profits of F ($100 × 6 years beginning with 1975 × 100 percent of the stock in F) under section 1248(a), and, under § 7.367(b)–12(e)(2), the section 1248(c)(2) amount of $900 attributed to the stock in Y received by F pursuant to the earlier transaction, $20 of earnings and profits accumulated by Y in 1980 ($100 × 100 percent × 20 percent of the stock in Y), and $18 of earnings and profits accumulated by F1 and F2, respectively, in 1980 ($100 × 100 percent × 20 percent × 90 percent of the stock in F1).

Example (12). On December 31, 1980, after the transaction described in example (10), F1 makes a pro-rata distribution of $180, no part of which is subpart F income, to Y and X. Without regard to this distribution Y, F, F1, and F2 each has $100 of earnings and profits in 1980. On December 31, 1980, F1 has $100 of current earnings and profits and $50 of accumulated earnings and profits ($500 accumulated between 1975 and 1979—$450 by which the earnings and profits of F1 were reduced pursuant to the transaction in example (10)). Thus, $135 ($150 × 90 percent of the stock in F1) of the distribution to Y is a dividend. Y's basis in the stock in F1 is reduced under section 301(c)(2) by $27.

On January 1, 1981, A sells all its stock in F. Upon this sale, A's section 1248 amount is $1,565. This amount consists of $600 of earnings and profits of F ($100 × 6 years beginning with 1975 × 100 percent of the stock in F), the section 1248(c)(2) amount of $900 attributed to the stock in Y received by F pursuant to the earlier transaction, $47 of the $235 of earnings and profits accumulated by Y in 1980 ($100 plus the $135 dividend from F1) and $18 of the $100 of earnings and profits accumulated by F2 in 1980. (After the $180 distribution, F1 has no earnings and profits attributable to the stock in F sold by A. See §§ 1.1248–2(d)(1) and 1.1248–3(b)(3).)

Example (13). On December 31, 1980, after the transaction described in example (10), Y sells all its stock in F1 and recognizes gain of $1,200. Without regard to this sale, Y, F, F1, and F2 each has $100 of earnings and profits in 1980. On January 1, 1981, A sells all its stock in F. Upon this sale, A's section 1248 amount is $1,760. This amount consists of $600 of earnings and profits of F, the section 1248(c)(2) amount of $900 attributed to the stock in Y received by F pursuant to the earlier transaction, and $260 of the $1,300 of earnings and profits accumulated by Y in 1980 ($100 plus the $1,200 gain on the sale of the stock in F1). (The earnings and profits accumulated by F1 and F2 in 1980 have been otherwise taken into account under section 1248, within the meaning of section 1248(c)(2)(C), by virtue of the inclusion in Y's earnings and profits of Y's gain on the sale of the stock in F1.)

Example (14). F is a foreign corporation that was organized on January 1, 1975. At all times since this date, A, a domestic corporation, has owned 100 percent of the outstanding stock in F.

(a) The F stock does not comprise substantially all of A's assets. On January 1, 1980, A exhanges all of its stock in F for 80 percent of the outstanding stock in Y, an unrelated foreign corporation. The exchange of stock in F by A would be described in section 351 if the status of Y as a corporation is recognized. This exchange would also be described in section 354 (a reorganization described in section 368(a)(1)(B)) if the status of F and Y as corporations is recognized. Under § 7.367(b)–4, the exchange is considered to be one described in section 351 to which F is not a party. Accordingly, the exchange is one described in section 367(a)(1), and §§ 7.367(b)–1 through 7.367(b)–12 (other than § 7.367(b)–4) do not apply to the exchange.

(b) The F stock does comprise substantially all of A's assets. On January 1, 1980, A transfers all of its stock in F to Y, an unrelated foreign corporation, in exchange for 70 percent of Y's outstanding stock. A then distributes all of its assets, including the Y stock received in the exchange, to its shareholders. The exchange of stock in F by A would be described in section 361 (a reorganization described in section 368(a)(1)(C)) if the status of Y as a corporation is recognized. This exchange would also be described in section 354 (a reorganization described in section 368(a)(1)(B)) if the status of F and Y as corporations is recognized. Under § 7.367(b)–4(b), the exchange is considered to be one described in section 361 to which F is not a party. Accordingly, the exchange is one described in section 367(a)(1), and §§ 7.367(b)–1 through 7.367(b)–12 (other than § 7.367(b)–4) do not apply to the exchange.

Example (15). F is a foreign corporation that was organized on January 1, 1979. At all times since this date, A, a domestic corporation, has owned all of the outstanding stock in F. On December 31, 1981, foreign corporation Y acquires all the assets of F in return for voting stock in Y. A exchanges all of its stock in F for the stock in Y and F is liquidated. After the transaction, A is a United States shareholder of Y, and Y is a controlled foreign corporation. Section 354 would apply to the exchange of the stock in F by A, and the transaction would qualify as a reorganization described in section 368(a)(1)(C), if the status of F and Y as corporations is recognized. As of December 31, 1981, F has a deficit in earnings and profits of ($300). A's section 1248 amount with respect to F is also ($300). Assume F had a net operating loss carryover that section 382(b)(2) required to be reduced by 20 percent.

Since A is a United States shareholder of controlled foreign corporation Y, § 7.367(b)–9 applies to the exchange as provided in § 7.367(b)–7(b). Thus, A's section 1248 amount is attributed to the stock in Y received by A. Pursuant to § 7.367(b)–11(c), the amount of the deficit in earnings and profits of F by which the deficit in earnings and profits of Y is increased under § 7.367–9(b)(2) and (c), is reduced by 20 percent from ($300) to ($240). As provided in § 7.367(b)–11 (b) and (d), this deficit and the section 1248 amount attributed to the stock in Y received by A shall be used only in the manner prescribed in section 381(c)(2)(B) and the regulations thereunder.

Example (16). F and G are foreign corporations engaged in the same business activity that were organized on January 1, 1975. At all times since this date, A and B, domestic corporations, have each owned 50 percent of the outstanding stock in F and G, respectively. On January 1, 1980, G acquires all the assets of F in return for G's voting stock. A and B exchange all their stock in F for stock in G, and F is liquidated. After the transaction, G continues the business activity of F and G unchanged. Section 354 would apply to the exchange of the stock in F by A and B, and the transaction would qualify as a reorganization described in section 368(a)(1)(D), if the status of F and G as foreign corporations is recognized. Under § 7.367(b)–4(d), the transaction is not considered to be a reorganization described in section 368(a)(1)(F) for purposes of section 367 and §§ 7.367(b)–1 through 7.367(b)–12, even though it might be considered to be a reorganization described in section 368(a)(1)(F) for other purposes. Thus, the attribution rules of § 7.367(b)–9 apply by reason of § 7.367(b)–7(b).

Example (17). F and F1 are foreign corporations that were organized on January 1, 1960. X is a domestic corporation that was organized on the same date. At all times since this date, X has owned 100 percent of the outstanding stock in F, and F has owned 100 percent of the outstanding stock in F1. D is a domestic corporation that was organized on January 1, 1976. At all times since this date, X has owned 100 percent of the outstanding stock in D. From January 1, 1960 until January 1, 1974, A, a domestic corporation, owned 100 percent of the outstanding stock in X. On January 1, 1974, B, a domestic corporation, purchased stock in X from A in a taxable sale, and, at all times since this date, A and B each has owned 50 percent of the outstanding stock in X. F, F1, X, D, A, and B each uses the calendar year as its taxable year. As of January 1, 1978, X, F, F1, and D have earnings and profits or deficits as follows:

	X		F		F1		D	
	E&P	Deficit	E&P	Deficit	E&P	Deficit	E&P	Deficit
1960		(200)		(100)		(200)		
1961		(200)		(100)		(200)		
1962		(200)		(100)		(200)		
1963		(200)	100			(200)		
1964		(200)	100			(200)		
1965	100		100		100			
1966	100		100		100			
1967	100		100		100			
1968	100		100		100			
1969	100		100		100			
1970	100		100		100			
1971	100		100		100			
1972	100		100		100			
1973	100		100		100			
1974	100		100		100			
1975	100		100		100			
1976	100		100		100			(100)
1977	100		100		100			(100)
Total	1,300	(1,000)	1,500	(300)	1,300	(1,000)		(200)

On January 1, 1978, X distributes all of its stock in F to A in exchange for half of A's stock in X. A's basis in the stock in X that A exchanged is $1,000, and the fair market value of the stock in F that A receives is $2,000. After the distribution, A owns 33 percent and B owns 67 percent of the stock in X.

(a) Section 1248(f) applies to the distribution by X of its stock in F since X is a domestic corporation. See § 7.367(b)–10(b). Thus, X must include the amount computed under section 1248(f)(1) in its gross income as a dividend for 1978. After the distribution, the net fair market value of the assets of the distributing group, X and D, exclusive of the stock in D, equals the net fair market value of the assets of the controlled group, F and F1, exclusive of the stock in F1. Section 355 would apply to the distribution (assuming the conditions of section 355(a)(1) (B) and (C) are met) if the status of F as a corporation is recognized. A and X comply with the reporting requirements of § 7.367(b)–1(c), and X, F, and F1 comply with the recordkeeping requirement of § 7.367(b)–1(d).

The provisions of § 7.367(b)–10(d) through (f) apply to the distribution of the stock in F by reason of § 7.367(b)–10(b). In accordance with § 7.367(b)–10(d), the earnings and profits and deficits of X, F, F1, and D are allocated so that, after the distribution, the distributing group and the controlled group each has total gross earnings and profits of $2,050 ($4,100 total gross earnings and profits of X, F, F1, F1, and D/2), and a total deficit of ($1,250) (($2,500) total gross deficit of X, F, and D/2), as follows:

	E&P	Deficit
Distributing Group:		
X	$2,050	($1,050)
D		(200)
Total	2,050	(1,250)
Controlled Group:		
F	1,098	(288)
F1	952	(962)
Total	2,050	(1,250)

X's earnings and profits consist of $1,300 actually accumulated by X, $402 allocated from F ($750 allocated from the controlled group X $1,500 earnings and profits of F/ $2,800 gross earnings and profits of the controlled group), and $348 allocated from F1 ($750 X $1,300/$2,800). X's deficit consists of ($1,000) acutally incurred by X, ($12) allocated from F (($50) X ($300)/($1,300)), and ($38) allocated from F1 (($50) X ($1,000)/ ($1,300)). The ($50) deficit allocated to X from F and F1 may be used only as provided in § 7.637(b)–11(b).

A, the only United States shareholder (determined after the distribution) of the controlled group (the group from which in this case the allocation of earnings and profits was made), makes a consent dividend election, described in § 7.367(b)–10(f), in the notice required by § 7.367(b)–1(c). Thus, the $348 of earnings and profits allocated from F1 to X is treated as if, immediately after the distribution of the stock in F, it had been distributed as a dividend to F. (See sections 551 and 951 for possible consequences to A of the consent dividend election.) Since the election under § 7.367(b)–10(f) is made, the basis of F in the stock in F1 is increased by $348 under § 7.367(b)–10(e)(1). In addition, whether or not this election is made, the basis of F in the stock in F1 is decreased under § 7.367(b)–10(e)(1) by the ($38) deficit allocated from F1 to X. Of this decrease, $23 (($38)×($600) pre-1963 gross deficit of F1/ ($1,000) gross deficit of F) is in respect of pre-1963 deficits and so shall be taken into account, as provided in § 7.367(b)–10(e)(2), only for purposes of computing the all earnings and profits and additional earnings and profits amounts with respect to subsequent transactions.

F is considered to be a corporation and section 355 applies to the distribution by X of the stock in F.

(b) The facts are the same as in example 17(a) except that X is a foreign corporation instead of a domestic corporation. After the distribution by X to A of the stock in F in exchange for half of A's stock in X, the fair market value of the stock in F owned by A equals the fair market value of the stock in X owned by A. Section 355 would apply to the distribution (assuming the conditions of section 355(a)(1) (B) and (C) are met) if the status of F and X as corporations is recognized. A complies with the reporting requirements of § 7.367(b)–1(c), and X, F, and F1 comply with the recordkeeping requirements of § 7.367(b)–1(d).

The application of § 7.367(b)–10 (d) through (f) results in the same allocation of earnings and profits and deficits and adjustments to basis as in example 17(a). In addition, under § 7.367(b)–10 (g), the following amounts are computed with reference to A's and B's stock in X prior to the distribution.

	A	B
Section 1248 amount	$1,650	$600
All earnings and profits amount	150	200
Additional earnings and profits amount	(300)	0

Under § 7.367(b)–10(h), half of each of these amounts of A is attributed to the stock in X and F, respectively, owned by A after the distribution. All of each of these amounts of B is attributed to the stock in X owned by B after the distribution.

X and F are considered to be corporations and section 355 applies to the distribution by X of the stock in F.

(c) The facts are the same as in example (17)(b) except that X distributes its stock in D (rather than its stock in F) to A in exchange for half of A's stock in X. Section 355 would apply to the distribution (assuming the conditions of section 355(a)(1) (B) and (C) are met) if the status of X as a corporation is recognized. A's basis in the stock in X which A exchanges is $1,000 and the fair market value of the stock in D that A receives is $2,000. After the distribution, the net fair market value of the assets of the distributing group, X, F, and F1, exclusive of the stock in F and F1, equals the net fair market value of the assets of the controlled group, D. The value of the stock in D owned by A equals the value of the stock in X owned by A. A complies with the reporting requirements of § 7.367(b)–1(c), and X, F, F1, and D comply with the recordkeeping requirements of § 7.367(b)–1(d).

After the allocation required by § 7.367(b)–10(d), the earnings and profits and deficits of the groups are as follows:

	E & P	Deficit
Distributing Group:		
X	$650	($543.50)
F	750	(163.00)
F1	650	(543.50)
Total	2,050	(1,250.00)
Controlled Group:		
D	2,050	(1,250)

D's earnings and profits consist of $650 allocated from X ($2,050 allocated from distributing group X $1,300 gross earnings and profits of X/$4,100 gross earnings and profits of distributing group), $750 allocated from F ($2,050 X $1,500/$4,100), and $650 allocated from F1 ($2,050 X $1,300/$4,100). D's deficit consists of ($200) actually incurred by D, ($137) allocated from F (($1,050) allocated from Distributing group X ($300) gross deficit of F/($2,300) gross deficit of distributing group), and ($456.50) allocated from X and F1, respectively (($1,050) X ($1,000)/($2,300)).

A and B, the United States shareholders (determined after the distribution) of the distributing group (the group from which in this case the allocation of earnings and profits was made), make a consent dividend election, described in § 7.367(b)–10(f), in the notice required by § 7.367(b)–1(c). Thus, the $650 of earnings and profits of F1 allocated to D is treated as if, immediately after the distribution of the stock in D, it had been distributed as a dividend through F to X. The $750 of earnings and profits of F allocated to D is treated as if, immediately after the distribution, it had been distributed as a dividend to X. See sections 551 and 951 for possible consequences to A and B of the consent dividend election. Since this election is made, the basis of F in the stock in F1 is increased by $650, and the basis of X in the stock in F is increased by $1,400 ($650 + $750) under § 7.367(b)–10(e)(1). In addition, whether or not this election is made, the basis of F in the stock in F1 is decreased by the ($456.50) deficit allocated from F1 to D. Of this decrease, $273.90 (($456.50 X ($600) pre-1963 gross deficit of F1/($1,000) gross deficit of F1) is in respect of a pre-1963 deficit and so shall be taken into account only for purposes of computing the all earnings and profits and additional earnings and profits amounts with respect to subsequent transactions. The basis of X in the stock in F is decreased by $593.50 (($456.50) + ($137) deficit allocated from F to D). Of this decrease, $410.90 (($273.90) + ($137)) is in respect of a pre-1963 deficit and so shall be taken into account only for purposes of computing the all earnings and profits and additional earnings and profits amounts with respect to subsequent transactions.

Under § 7.367(b)–10(h), half of A's section 1248 amount of $1,650, all earnings and profits amount of $150, and additional earnings and profits amount of ($300) is attributed to the stock in X owned by A after the distribution of the stock in D. No amounts are attributed to the stock in D owned by A after the distribution. See § 7.367–10(i)(1). All of B's section 1248 amount of $600, all earnings and profits amount of $200, and additional earnings and profits amount of $0 is attributed to the stock in X owned by B after the distribution. Section 7.367(b)–10(i) applies since A received stock in D, a domestic corporation. Accordingly, A includes in gross income as a dividend $825 ($1,650 section 1248 amount—$825attributed to stock in X owned by A after the distribution). This amount increases the earnings and profits of A but does not decrease the earnings and profits of X, F, F1, or D.

X is considered to be a corporation and section 355 applies to the distribution by X of the stock in D.

There is a need for immediate guidance with respect to the provisions contained in this Treasury decision. For this reason, it is found impracticable to issue it with notice and public procedure under subsection (b) of section 553 of Title 5 of the United States Code or subject to the effective date limitation of subsection (d) of that section.

This Treasury decision is issued under the authority contained in sections 367 (b) and 7805 of the Internal Revenue Code of 1954 (90 Stat. 1634 and 68A Stat. 917; 26 U.S.C. 367 (b) and 7805).

Jerome Kurtz,

Commissioner of Internal Revenue.

Approved: September 17, 1979.

Donald C. Lubick,

Assistant Secretary of the Treasury.

[FR Doc. 79–30828 Filed 10–4–79; 8:45 am]

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DEPARTMENT OF LABOR

Office of the Secretary

29 CFR Part 14

Security Regulations

AGENCY: Department of Labor.

ACTION: Final rule.

SUMMARY: In compliance with Executive Order No. 12065, June 28, 1978, 43 FR 28949, entitled National Security Information, the Department of Labor publishes its policy concerning declassification of agency information, its guidelines for systematic declassification review and its guidelines for dissemination of such information to persons outside the executive branch, including historical researchers and former Presidential appointees.

EFFECTIVE DATE: This document is effective November 5, 1979.

ADDRESS: The Department of Labor Manual Series (DLMS), referred to in the Supplementary Information, are available for inspection at the Office of Management Systems in the Directorate of Management Policy, Department of Labor, Room S5522, 200 Constitution Avenue, N.W., Washington, D.C. 20210, 202-523-6438.

FOR FURTHER INFORMATION CONTACT: William J. McLaughlin, Director, Office of Emergency Preparedness Planning, Room C5315, 200 Constitution Avenue, N.W., Washington, D.C. 20210, 202-523-6963.

SUPPLEMENTARY INFORMATION: Section 5-402 of Executive Order No. 12065, June 28, 1978, 43 FR 28949 at 28960, provides as follows:

> Unclassified regulations that establish agency information security policy and unclassified guidelines for systematic declassification review shall be published in the Federal Register.

In order to comply with this requirement, the Department of Labor has herein excerpted from its Dept. of Labor manual Series (DLMS-2 Administration, Chapter 300-Security Regulations) the policies and procedures concerning agency information security and its guidelines for systematic declassification review. These excerpts also include internal guidelines for dissemination of such information to persons outside the executive branch, including historical researchers and former Presidential appointees. The complete Dept. of Labor manual Series (DLMS-2 Administration, Chapter 300-Security Regulations) are not published herein because they contain internal procedures which are public but which are not of a nature warranting publication in the Federal Register due to the fact that they effectuate the policy set forth in the attached document. However, the complete DLMS-2 Administration Series, Chapter 300-Security Regulations is available for public inspection and copying. Interested persons should make inquiries to the Contact Officer shown or write to the indicated address.

The Department of Labor has had no authority to classify documents since December 1, 1978. Accordingly, this part applies only to documents classified by the Department of Labor before that date. This procedure does not apply to information in the Department's possession which was classified by other agencies.

Part 14, entitled National Security Information, is being revised, including its title. As revised, Part 14 reads as follows:

PART 14—SECURITY REGULATIONS

Subpart A—Introduction to Security Regulations

Subpart B—Review of Classified Information.

Subpart C—Transmission of Classified Information.

Authority: Executive Order No. 12065, June 28, 1978, 43 FR 28949.

Subpart A—Introduction to Security Regulations

§ 14.1 Purpose.

These regulations implement Executive Order 12065, entitled National Security Information, dated June 28, 1978, and directives issued pursuant to that Order through the National Security Council and the Atomic Energy Act of 1954, as amended.

§ 14.2 Policy.

The interests of the United States and its citizens are best served when information regarding the affairs of Government is readily available to the public. Provisions for such an informed citizenry are reflected in the Freedom of Information Act (5 U.S.C. 552) and in the current public information policies of the executive branch.

(a) *Safeguarding national security information.* Some official information within the Federal Government is directly concerned with matters of national defense and the conduct of foreign relations. This information must, therefore, be subject to security constraints, and limited in terms of its distribution.

(b) *Exemption from public disclosure.* Official information of a sensitive nature, hereinafter referred to as national security information, is expressly exempted from compulsory public disclosure by Section 552(b)(1) of Title 5 U.S.C. Persons wrongfully disclosing such information are subject to prosecution under the Federal Criminal Code.

(c) *Scope.* To ensure that National Security information is protected, but only to the extent and for such a period as is necessary, these regulations:

(1) Identify information to be protected.

(2) Prescribe procedures on classification, declassification, downgrading, and safeguarding of information.

(3) Establish a monitoring system to ensure the effectiveness of the Department of Labor (DOL) Security program and regulations.

(d) *Limitation.* The need to safeguard National Security information in no way implies an indiscriminate license to withhold information from the public. It is important that the citizens of the United States have access, consistent with national security, to information concerning the policies and programs of their Government.

§ 14.3 DOL Classification Review Committee.

A DOL Classification Review Committee is hereby established.

(a) *Composition of committee.* The members of this Committee are:

Chairperson—Director, Administrative Programs and Services, OASAM.
Member—Director, Office of Management, Administration and Planning, Bureau of International Affairs.
Member—Security Officer, Bureau of Labor Statistics.
Member—Security Officer, Occupational Safety and Health Administration.
Member—Administrative Officer, Office of the Solicitor.
Member—Assistant Inspector General, Office of Inspector General.

(b) *Responsibilities.* The Committee is responsible for:

(1) Acting on all suggestions and complaints arising with respect to the DOL's information security program.

(2) Reviewing all appeals of requests for records under the Freedom of Information Act, 5 U.S.C. 552, when the proposed denial is based on continued classification under Executive Order 12065.

(3) Recommending to the Secretary of Labor appropriate administrative action to correct abuses or violations of any provision of Executive Order 12065 or directives thereunder. Recommended administrative actions may include notification by warning letter, formal reprimand, and, to the extent permitted by law, suspension without pay and removal. Upon receipt of any such recommendation, the Secretary shall immediately advise the Committee of the action taken.

§ 14.4 Definitions.

The following definitions apply under these regulations:

(a) *Primary organizational unit*—refers to the Office of the Secretary, Office of the Solicitor, Labor-Management Services Administration, Employment and Training Administration, Occupational Safety and Health Administration, Mine Safety and Health Administration, Employment Standards Administration, and the Bureau of International Affairs, and any other agency of the Department of Labor whose documents have been classified in the interest of National Defense.

(b) *Classify*—to assign information to one of the classification categories after determining that the information requires protection in the interests of national security.

(c) *Courier*—an individual designated by appropriate authority to protect classified and administratively controlled information in transit.

(d) *Custodian*—the person who has custody or is responsible for the custody of classified information.

(e) *Declassify*—the authorized removal of an assigned classification.

(f) *Document*—any recorded information regardless of its physical form or characteristics, including (but not limited to):

(1) Written material—(whether handwritten, printed or typed).

(2) Painted, drawn, or engraved material.

(3) Sound or voice recordings.

(4) Printed photographs and exposed or printed films (either still or motion picture).

(5) Reproductions of the foregoing, by whatever process.

(g) *Downgrade*—to assign lower classification than that previously assigned.

(h) *Derivative classification*—a determination that information is in substance the same as information that is currently classified. It is to incorporate, paraphrase, restate or generate in new form information that is already classified (usually by another Federal agency).

(i) *Information Security Oversight Office*—an office located in the GSA that monitors the implementation of E.O. 12065.

(j) *Interagency Information Security Committee*—pursuant to E.O. 12065, an Interagency Information Security Committee (IISC) has been established. It is chaired by the Director of the Information Security Oversight Office and is comprised of representatives of the Secretaries of State, Defense, Treasury, and Energy, the Attorney General, the Director of Central Intelligence, the National Security Council, the Domestic Policy Staff, and the Archivist of the United States. Representatives of other agencies may be invited to meet with the Committee on matters of particular interest to those agencies. The Committee shall meet at the call of the Chairperson or at the request of a member agency and shall advise the Chairperson on implementation of E.O. 12065.

(k) *Marking*—the physical act of indicating the assigned security classification on national security information.

(l) *Material*—any document, product, or substance on or in which information is recorded or embodied.

(m) *Nonrecord material*—extra copies and duplicates, the use of which is temporary, including shorthand notes, used carbon paper, preliminary drafts, and other material of similar nature.

(n) *Paraphrasing*—a restatement of the text without alteration of its meaning.

(o) *Product and substance*—any item of material (other than a document) in all stages of development, processing, or construction and including elements, ingredients, components, accessories, fixtures, dies, models, and mockups associated with such items.

(p) *Record material*—all books, papers, maps, photographs, or other documentary materials, regardless of physical form or characteristics, made or received by the U.S. Government in connection with the transaction of public business; this includes material preserved by an agency or its legitimate successor as evidence of its organization, functions, policies, decisions, procedures, or other activities, or because of the informational data contained therein.

(q) *True reading*—the unparaphrased literal text.

(r) *Upgraded*—to assign a higher classification than that previously assigned.

Subpart B—Review of Classified Information

§ 14.10 Mandatory review for declassification.

(a) *Scope of review.* The mandatory review procedure applies to information originally classified by the DOL when it had such authority, i.e. before December 1, 1978. Requests may come from members of the public or a government employee or agency. The procedures do not apply to information originated by other agencies and merely held in possession of the DOL. Requests for disclosure submitted under provisions of the Freedom of Information Act are to be processed in accordance with provisions of that Act.

(b) *Where requests should be directed.* Requests for mandatory review for declassification should be directed to the Department of Labor, Office of the Assistant Secretary for Administration and Management, (OASAM), Wash., D.C. 20210. Requests should be in writing and should reasonably describe the classified information to allow identification. Whenever a request does not reasonably describe the information sought, the requestor will be notified that unless additional information is provided or the scope of the request is narrowed, no further action will be undertaken.

(c) *Processing.* The OASAM will assign the request to the appropriate DOL office for declassification consideration. A decision will be made within 60 days as to whether the requested information may be declassified and, if so, made available to the requestor. If the information may not be released in whole or in part, the requestor will be given a brief statement as to the reasons for denial, and a notice of the right to appeal the determination to the DOL Classification Review Committee, Office of the Assistant Secretary for Administration and Management, Washington, D.C. 20210. The requestor is to be told that such an appeal must be filed with the DOL within 60 days.

(d) *Appeals procedure.* The DOL Classification Review Committee will review and act within 30 days upon all applications and appeals for the declassification of information. The Committee is authorized to overrule, in behalf of the Secretary, Agency determinations in whole or in part, when it decides that continued protection is not required. It will notify the requestor of the declassification and provide the information. If the Committee determines that continued classification is required, it will promptly notify the requestor and provide the reasons for the determination.

(e) *Burden of proof.* In evaluating requests for declassification the DOL Classification Review committee will require the DOL office having jurisdiction over the document to prove that continued classification is warranted.

(f) *Fees.* If the request requires a service for which fair and equitable fees may be charged pursuant to Title 5 of the Independent Offices Appropriation Act, 31 U.S.C. 483a (1976), the requestor will be notified and charged.

Subpart C—Transmission of Classified Information

§ 14.20 Dissemination to individuals and firms outside the executive branch.

Requests for classified information received from sources outside the executive branch of the Federal Government, provided the information has been originated by the DOL, will be honored in accordance with the following guidelines:

(a) *Top Secret Information.* All requests for Top Secret Information by an individual or firm outside the executive branch must be referred promptly to the OASAM for consideration on an individual basis.

(b) *Secret and Confidential Information.* Subject to the restrictions below, Secret or Confidential information may be furnished to an individual or firm outside the executive branch if the action furthers the official program of the organizational unit in which the information originated. The official furnishing such information must ensure that the individuals to whom the information is to be furnished have the appropriate DOL clearance, or at least clearance for the same or higher classification from another Federal department, or outside agency whose security clearances are acceptable to the DOL. The official must also ensure that the person to whom the classified information is being furnished possesses the proper facilities for safeguarding such information. *No Secret or Confidential information may be furnished to an individual or firm outside the executive branch without written concurrence from the primary organizational unit head or the Security Officer of that unit.*

(c) *Unauthorized knowledge of classified information.* Upon receipt of a request for classified information which raised a suspicion that an individual or organization outside the executive branch has unauthorized knowledge of the existence of Confidential, Secret, or Top Secret information, a report providing all available details must be immediately submitted to the DOL Document Security Officer for appropriate action and disposition.

(d) *Requests from outside the United States.* All requests from outside the United States for Top Secret, Secret or Confidential information, except those received from foreign offices of the primary organizational unit or from U.S. embassies or similar missions, will be referred to the Deputy Under Secretary for International Affairs.

(e) *Access by historical researchers.* Individuals outside the executive branch engaged in historical research may be authorized access to classified information over which the DOL has jurisdiction provided:

(1) The research and need for access conform to the requirements of Section 4–302 of Executive Order 12065.

(2) The information requested is reasonably accessible and can be located and compiled with a reasonable amount of effort.

(3) The researcher agrees to safeguard the information in a manner consistent with E.O. 12065 and directives thereunder.

(4) The researcher agrees to a review of the notes and manuscript to determine that no classified information is contained therein.

Authorization for access is valid for the period required but no longer than 2 years from the date of issuance unless it is renewed under the conditions and regulations governing its original authorization.

(f) *Access by former presidential appointees.* Individuals who have previously occupied policymaking positions to which they were appointed by the President may be authorized access to classified information which they originated, reviewed, signed, or received while in public office. Upon request, information identified by such individuals will be reviewed for declassification in accordance with the provisions of these regulations.

§ 14.21 Release of classified information to foreign governments.

National security information will be released to foreign governments in accordance with the criteria and procedures stated in the President's Directive entitled "Basic Policy Governing the Release of Classified Defense Information to Foreign Governments" dated September 23, 1958. All requests from Foreign Governments for the release of such information will be referred to the Deputy Under Secretary for International Affairs.

§ 14.22 Availability of classified information to persons not employed by the Department of Labor.

(a) *Approval for access.* Access to classified information in the possession or custody of the primary organizational units of the Department by individuals who are not employees of the executive branch shall be approved in advance by the DOL Document Security Officer.

(b) *Access to Top Secret Material.* Access to Top Secret Information within the primary organizational units of the DOL by employees of other Federal agencies must be approved in advance by the Top Secret Control Officer of the primary organizational unit.

(c) *Access to Secret and Confidential Information.* Secret and Confidential information may be made available to properly cleared employees of other Federal departments or outside agencies if authorized by the primary organizational unit having custody of the information.

Signed at Washington, D.C., on this 1st day of October, 1979.

Alfred M. Zuck,

Assistant Secretary for Administration and Management.

[FR DOC 79-30934 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-23-M

DEPARTMENT OF DEFENSE

Department of the Navy

32 CFR Part 706

Certifications and Exemptions Under the International Regulations for Preventing Collisions at Sea, 1972; Amendment

AGENCY: Department of the Navy, DOD.

ACTION: Final rule.

SUMMARY: The Department of the Navy is amending its certifications and exemptions under the International Regulations for Preventing Collisions at Sea, 1972 (72 COLREGS) to reflect that the Secretary of the Navy: (1) has determined that USS *Bremerton* (SSN 698) is a vessel of the Navy which, due to its special construction and purpose, cannot comply fully with certain provisions of the 72 COLREGS without interfering with its special function as a naval submarine; and (2) has found that USS *Bremerton* (SSN 698) is a member of the SSN 688 class of ships, exemptions for which have previously been granted under 72 COLREGS Rule 38. The intended effect of this rule is to warn mariners in waters where 72 COLREGS apply.

EFFECTIVE DATE: September 19, 1979.

FOR FURTHER INFORMATION CONTACT: Lieutenant Commander M. D. Seiders, JAGC, USN, Admiralty Division, Office of the Judge Advocate General, Navy Department, Washington, D.C., Telephone number (202) 694-5188.

SUPPLEMENTARY INFORMATION: This amendment to Part 706 provides notice that the Secretary of the Navy has certified that USS *Bremerton* (SSN 698) is a vessel of the Navy which, due to its special construction and purpose, cannot comply fully with 72 COLREGS: Rule 21(c) regarding the arc of visibility and location of the stern light; Annex I, section 2(a) (i) regarding the height of the masthead light; Annex I, section (2k) regarding the height and relative positions of the anchor lights; and Annex I section 3(b) regarding the location of the sidelights. Full compliance with the above-mentioned 72 COLREGS provisions would interfere with the special function of the ship. The Secretary of the Navy has also certified that the above-mentioned lights are located in closest possible compliance with the applicable 72 COLREGS requirements.

Notice is also provided to the effect that USS *Bremerton* (SSN 698) is a member of the SSN 688 class of ships for which certain exemptions, pursuant to 72 COLREGS Rule 38, have been previously authorized by the Secretary of the Navy. The exemptions pertaining to that class, found in the existing tables of § 706.3, are equally applicable to USS *Bremerton.*

Moreover, it has been determined, in accordance with 32 CFR Parts 296 and 701, that publication of this amendment for public comment prior to adoption is impracticable, unnecessary, and contrary to public interest since it is based on technical findings that the placement of lights on this ship in a manner differently from that prescribed herein will adversely affect the ship's ability to perform its military function. Accordingly, 32 CFR Part 706 is amended as follows:

§ 706.2 [Amended]

1. The third Table One of § 706.2 is amended as follows to indicate certifications issued by the Secretary of the Navy:

Vessel	No.	Distance in meters of forward masthead light below minimum required height. § 2(a)(i), annex I
* * * * *		
USS Indianapolis	SSN 697	
USS Bremerton	SSN 698	3.49
* * * * *		

2. Table Three of § 706.2 is amended as follows to indicate certifications issued by the Secretary of the Navy:

Vessel	No.	Masthead light, arc of visibility; rule 21(a)	Sidelights, arc of visibility; rule 21(b)	Stern light, arc of visibility; rule 21(c)	Sidelights, distance inboard of ship's sides in meters; § 3(b), annex I	Stern light, distance forward of stern in meters; rule 21(c)	Forward anchor light, height above hull in meters; § 2(k), annex I	Anchor lights, relationship of aft light to forward light in meters, § 2(k), annex I
* * * * *								
USS Indianapolis	SSN 697							
USS Bremerton	SSN 698			209°	4.2	6.1	3.5	1.7 below
* * * * *								

(EO 11964 and 33 U.S.C. § 1605.)

Effective Date: The effective date of this amendment will be September 19, 1979.

Dated: September 19, 1979.

R. James Woolsey,
Acting Secretary of the Navy.

[FR Doc. 79-31028 Filed 10-4-79; 8:45 am]

BILLING CODE 3810-71-M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[FRL 1333-7]

Final Rulemaking on Approval of Colorado State Implementation Plan

AGENCY: Environmental Protection Agency.

ACTION: Final Rulemaking.

SUMMARY: The purpose of this notice is to approve, in part, the State Implementation Plan (SIP) revision for Colorado which was received by EPA on January 2, 1979. In addition, EPA is taking final action to conditionally approve some elements of the Colorado SIP. The conditional approval requires Colorado to submit additional materials to satisfy the conditions. This plan revision was prepared by the State to meet the requirements of Part D (Plan Requirements for Nonattainment Areas) of the Clean Air Act (the Act), as amended in 1977. On May 11, 1979 (44 FR 27693), EPA published a notice of proposed rulemaking which described the nature of the SIP revision, discussed certain provisions which in EPA's judgment did not comply with the requirements of the Act, and requested public comment. Numerous comments were received.

The Environmental Protection Agency (EPA) has reviewed public comments received on the May 11, 1979, proposal and is taking the following actions:

1. Approval—a. Strategy for Colorado Springs (The urbanized area) as defined by the continuing, comprehensive, and cooperative planning process (3–C). Total Suspended Particulates (TSP); b. Strategy for Grand Junction (Mesa designated area) TSP; c. Strategy for Denver (3–C urbanized area), Nitrogen Dioxide; d. Strategy for Denver (designated area), TSP.

2. Conditional Approval—a. Denver (Counties of Arapahoe, Adams, Denver, Jefferson, Boulder, and Douglas), Ozone and Carbon Monoxide (CO); b. Colorado Springs (3–C urbanized area), CO; c. Larimer-Weld Region (Fort Collins and Greeley) CO; d. Strategy for Pueblo (3–C urbanized area), TSP; e. Regulation 3, "Process for Emission Permit Review"; f. Regulation 7 "Volatile Organic Compounds"; g. Inspection/ Maintenance Program; h. Section 172(b)(11)(A) of the Act (Alternatives Analysis).

3. No final action—a. Colorado Springs (El Paso County), Ozone; b. Larimer-Weld (designated area), TSP; c. Larimer-Weld Counties, Ozone; d. Larimer-Weld Transportation Control Measures Schedules (proposed elsewhere); e. Denver Transportation Control Measures Schedules (proposed elsewhere).

4. Disapproval—Regulation 3, Legal Authority Under Section 110 of the Act.

Elsewhere in today's Federal Register, EPA is inviting public comment on the acceptability of deadlines for complying with the conditions of approval. Also in that same notice, EPA is requesting comment on the acceptability of transportation control measures schedules for Denver and Larimer-Weld, submitted by the State on July 27, 1979, and July 5, 1979, respectively.

EPA has also chosen to take no action in areas which are being proposed for redesignation to unclassifiable or attainment under Section 107 of the Act and on the transportation control measures schedules for Denver and Larimer-Weld. Until EPA's "Final Rulemaking" on the redesignations, the SIP for these areas will not be approved.

In this notice the SIP is summarized, issues resulting in SIP approval, conditional approval and no action are discussed, and EPA's responses to relevant comments received on its proposal are included. It should be noted that only the requirements with respect to Part D of the Act are discussed, with one exception, Regulation 3.

EFFECTIVE DATE: Effective October 5, 1979.

FOR FURTHER INFORMATION CONTACT: Robert R. DeSpain, Chief, Air Programs Branch, Environmental Protection Agency, Region VIII, 1860 Lincoln Street, Denver, CO 80295, (303) 837–3471.

SUPPLEMENTARY INFORMATION:

Introduction

The information in this notice is divided into five sections entitled "INTRODUCTION," "BACKGROUND," "SIP DEFICIENCIES/CONDITIONAL APPROVAL," "PUBLIC COMMENTS ON PROPOSAL," and "EPA ACTIONS." This first section outlines the development of the Colorado SIP revision. The "BACKGROUND" section describes the Colorado SIP revision for each nonattainment area. The "SIP DEFICIENCIES/CONDITIONAL APPROVAL" section describes where the SIP is inadeqate because it did not accomplish enough and gives schedules and deadlines to correct these deficiencies, and how some deficiencies cited in the proposal were satisfied by the Governor's supplemental submittals on July 5, July 23, and July 27, 1979. The "PUBLIC COMMENTS ON PROPOSAL" section summarizes relevant comments received on the proposal and EPA's response to them. The "EPA ACTIONS" section explains EPA decision to approve, conditionally approve, or take no action, on the SIP based on considerations discussed in the two preceding sections.

The Colorado SIP revision was developed and submitted to EPA in response to the requirements of Part D of the Act. In general, the SIP is required to provide for attainment and maintenance of the national ambient air quality standards (NAAQS) for all areas which have been designated "nonattainment" pursuant to Section 107 of the Act. Specific requirements for an approvaable SIP are discussed in detail in the April 4, 1979, Federal Register (44 FR 20372).

On March 3, 1978 (43 FR 8962) and on September 11, 1978 (43 FR 40419), pursuant to Section 107 of the Act, EPA designated certain areas as nonattainment based on existing violations of the NAAQS. The designated nonattainment areas in Colorado are displayed in Table 1.

Table 1—Nonattainment Areas in Colorado

	Carbon monoxide (CO)	Ozone (O_3)	Total suspended particulates (TSP)	Nitrogen dioxide (NO_2)
Colorado Springs	X	X	X	
Denver Region	X	X	X	X
Grand Junction			X	
Larimer-Weld Region	X	X	X	
Pueblo			X	

In accordance with Section 174 of the Act, primary responsibility for preparing carbon monoxide (CO) and ozone control plans was delegated by the Governor to organizations of local elected officials. These organizations are the Pikes Peak Area Council of Governments (PPACG) for the Colorado Springs nonattainment areas the Denver Regional Council of Governments (DRCOG) for the Denver Region nonattainment areas, and the Larimer-Weld Regional Council of Governments (LWRCOG) for Larimer and Weld Counties. Designated regional planning agencies were generally responsible for development of transportation control measures, which were coordinated with the transportation planning process. The State was responsible for technical support to designated agencies as well as for Inspection/Maintenance (I/M) programs, stationary source control, new source review and any other programs encompassing areas beyond the authority of local governments.

The Governor also delegated that portion of total suspended particulates (TSP) plan development which involved transportation sources to regional planning agencies. In addition to the three named above, the Pueblo Area Council of Governments and the Grand Junction Air Quality Advisory Committee (in conjunction with the Colorado West Council of Governments) were designated lead planning agencies for TSP.

The locally prepared plans were submitted to the Colorado Air Quality Control Commission (Commission) during fall of 1978. The Commission modified each locally prepared plan prior to incorporation into the SIP. The Commission deemed such changes necessary to make the various locally prepared plans consistent with each other, with State policy, and with Federal requirements.

Following a public hearing, the Commission adopted the SIP and submitted it to the Governor of Colorado. The Governor submitted the SIP to EPA on January 2, 1979. The submittal was followed by a letter from the Governor on January 5, 1979, requesting time extensions for certain areas for meeting the CO and/or ozone standards.

In a January 19, 1979, letter to the Governor, EPA identified several items which required clarification and others which were omitted. On January 31, 1979, EPA received a partial response from the Air Quality Control Division, the technical support organization within the Department of Health, which contained information that was of assistance to EPA in its continuing review and a schedule for submitting the additional required information.

In a meeting between EPA and State officials on March 13, 1979, additional issues were raised by EPA. The Division responded by submitting clarifying material to EPA on March 15, 1979. EPA proposed action on the SIP revision in the Federal Register on May 11, 1979.

On July 5, 1979, the Governor submitted the final comments of the Commission with respect to issues raised in EPA's proposed action. On July 23, 1979, the Governor submitted, as part of the SIP, House Bills 1109 (the revised Colorado Air Quality Control Act), 1090 (amendments to the provision for burning solid wastes), and Senate Bill 1 (provisions for reducing motor vehicle emissions). At this time, EPA is taking no action on House Bill 1109 but will soon propose action in the Federal Register to invite comments on its acceptability. On July 27, 1979, the Governor submitted the DRCOG schedules for implementation of the transportation control strategies. Action is proposed on these schedules and on the schedules for Larimer-Weld elsewhere in today's Federal Register.

Background

The following discussion describes the nature of the air quality problems, the SIP revision for each nonattainment area, and related regulations.

For the areas where the Governor has requested redesignations, Larimer-Weld (primary TSP, ozone) and Colorado Springs (ozone), EPA has chosen to take no action on these portions of the SIP.

Colorado Springs Area

I. *Carbon Monoxide.* The Colorado Springs plan predicts attainment of the 8-hour CO standard during 1985 with implementation of the Federal Motor Vehicle Emission Control Program (FMVECP), an I/M program yet to be adopted, the Federal high altitude emission standards to be adopted for model year (MY) 1981, and the transportation control measures that are currently programmed for implementation. The plan also predicts reasonable further progress (RFP) towards attainment. The transportation control measures include transit improvements, improved carpool locator service, and traffic flow improvements.

The PPACG conducted a preliminary screening of all of the transportation control measures in section 108(f) of the Act and determined that certain measures required more study before a specific commitment to implement them could be made. Consequently, the plan provides that some of the measures will be analyzed and implemented prior to 1982 if they are found to be feasible for the area. The remaining measures will be analyzed as part of the long term transportation planning process with the completion of the analyses scheduled for February 1980, and implementation expected prior to 1985.

The City Council and County Commissioners adopted the CO plan. The schedules for developing and implementing measures that were provided in the locally prepared plan also consititute a commitment to implement the plan and to provide adequate resources.

II. *Total Suspended Particulates.* The Colorado Springs plan predicts attainment of the primary TSP standard by 1982 and requests an 18-month extension for submitting plans for attainment of the secondary standard. The particulate control measures selected for implementation are a modified street sanding program (initiated first as a pilot program to confirm estimates of effectiveness), control of mud and dirt carryout sources, paving of unpaved alleys and roads, and control of construction and grading operations.

Commitments to implement the locally prepared plan for TSP are provided in the form of resolutions adopted by the City of Colorado Springs and by PPACG which specifically provide for plan implementation.

Denver Area

I. *Nitrogen Dioxide.* The Denver area plan predicts attainment of the standard by 1982 as a result of the FMVECP. The NO_2 prediction was made using a linear rollback model.

II. *Carbon Monoxide and Ozone.* The analysis in the Denver plan predicts attainment of the 8-hour CO standard in 1987. This estimate assumes no additional controls beyond the FMVECP, an I/M program yet to be adopted, Regional Transportation District (RTD, Denver's public transit operator) Transit Development Plan (TDP), and the DRCOG carpool locator service. However, an additional 43% reduction would still be needed to achieve the standard by 1982.

Based on the same assumptions used in the CO modeling, the predicted 1987 ozone concentration exceeds the standard. Based on the predicted ozone concentration in 1982, an additional reduction of about 19% would still be necessary to meet the standard. A different set of assumptions was used in additional analyses (submitted July 27, 1979) which do show attainment by 1987.

The transportation measures included in the plan are commitments to either implement or study an expanded I/M program and possible implementation of retrofit (study), EPA implementation of the high altitude standards, smoking vehicle ordinances, TDP implementation and analysis by RTD of alternate funding sources, employer based incentives for ridesharing, variable work hours (study and demonstration), vanpool demonstration program, expanded carpool matching service, bicycle plan implementation and demonstration project, revised transportation project programming process to provide priority to air quality projects, high occupancy vehicle (HOV) lane study and implementation (where feasible), no drive day, Sante Fe Drive HOV lane, parking management plan, and land use assessment handbook (CO hotspot analysis).

III. *Total Suspended Particulates.* The predicted maximum annual average TSP concentration in 1982 indicates that a 29% reduction is necessary to achieve the primary NAAQS. The non-traditional particulate control measures selected for implementation are street cleaning practices, unpaved road controls, control of mud and dirt carry out sources, control of construction, grading, excavation, and demolition, and paving or stablizing unpaved roads and alleys. An 18-month extension for submittal of the plan to attain the secondary standard was requested.

Larimer-Weld Area

I. *Secondary TSP.* An 18-month extension for submittal of the plan to attain the secondary standard was requested.

II. *Carbon Monoxide.* The Larimer-Weld plan analysis predicts attainment of the CO standard by 1986 and 1984 in Fort Collins and Greeley, respectively, with implementation of the FMVECP, an I/M program yet to be adopted, and the adopted transportation control measures.

The transportation control measures in Section 108(f) adopted for implementation by the City of Greeley by 1982 are improved public transit, bicyle lanes, staggered work hours, vehicle fleet controls, and traffic flow improvements.

The measures adopted for implementation by the City of Fort Collins by 1982 are improved public transit, expanded carpool locator service, bicycle lanes, and traffic flow improvements at specified locations.

A commitment to implement the adopted control measures and to provide the resources needed to carry out the plan is provided in the form of resolutions adopted by each city and by LWRCOG.

Pueblo Area

TSP violations are caused by a combination of stationary source emissions and transportation related fugitive dust. The plan addresses the primary annual standard, since monitoring data shows that a greater degree of control is necessary to attain the annual standard. A plan adequate to attain the annual standard should also attain the 24-hour standard. An 18-month extension for submittal of the plan to attain the secondary standard was requested.

The control measures selected for implementation are paving roads in the City of Pueblo, control of construction sites, and additional emission reductions from specific stationary sources. The demonstration projects that will be implemented are paving roads outside the city, control mud carryout, paving alleys in the city, and double street sweeping/use of vacuum equipment.

Adequate commitments and schedules to undertake the required studies and to develop and implement the transportation-related fugitive dust control measures are contained in the plan.

Grand Junction Area

The plan addresses the annual primary standard for TSP since a greater degree of control is required to meet the annual standard than the 24-hour standard. An 18-month extension to submit the plan to attain the secondary standard was requested.

The plan demonstrates attainment of the primary standard. The control measures included in the strategy are a bikeway plan, control of mud and dirt carryout, and the paving or stabilizing of unpaved roads and alleys. A carpooling program and an improved street cleaning pilot program will be studied.

State Regulations

Section 172 of the Act requires that reasonably available control technology (RACT) be applied to existing stationary sources of air pollution in nonattainment areas. The Commission has eleven (11) air pollution control regulations of which three (3) must satisfy this RACT requirement. Regulation 1, which controls particulates, visible emissions, and sulfur oxides from stationary sources was revised for existing sources of sulfur oxides and for existing iron and steel facilities. Regulation 5 contains requirements for the control of existing alfalfa dehydration plants. Regulation 7, which provides for control of volatile organic compounds, was revised extensively.

In addition to the RACT requirement, Regulation 3, which includes the new stationary source review program, was revised to be consistent with the requirements of Section 173 of the Act. Regulation 9 requires large employers to offer incentives to employees to commute to and from work in other than single occupant vehicles. The incentives include providing information on bus routes, providing preferential parking to carpools and vanpools, and providing bicyle parking facilities. Regulation 10 establishes criteria that will be used to determine whether transportation projects and programs conform to the SIP as required under Section 176(c) of the Act and pursuant to Department of Transportation requirements in 23 U.S.C. 109(j) and 23 CFR Part 770. EPA is deferring action on Regulation 10 and will propose approval or disapproval in the near future. Regulation 11 provides requirements for the licensing and certification of inspectors, inspection facilities and emission measurement equipment for the inspection/maintenance program.

SIP Deficiencies/Conditional Approval

This section contains a discussion of deficiencies identified by EPA in the May 11, 1979, proposed rulemaking and during the public comment period, and includes deadlines and schedules to correct them.

These deficiencies are summarized first by portions of the SIP that apply statewide and were prepared by the Commission, and then by local plans prepared by the regional planning agencies. Also included in this section are clarifications by the Commission on deficiencies raised in the proposed rulemaking.

State-Developed SIP Provisions

I. *Inspection/Maintenance.* Section 172(b)(11)(B) of the Act requires that when the necessity for an extension for the attainment date for ozone in Denver and CO in Denver, Colorado Springs, and Larimer-Weld from 1982 up to 1987 has been demonstrated, the State must establish a specific schedule for implementing a motor vehicle I/M program. The Commission has demonstrated the need for an extension for CO and ozone in these areas. The Colorado legislature, in recognition of the need for an I/M program in these areas, passed Colorado Senate Bill 1 (as amended June 8, 1979). This bill initiates a program on January 1, 1981, for the Denver, Colorado Springs and Larimer-Weld metropolitan areas including a total of nine counties for 1968–79 model years. The bill also describes how the State will consider program alternatives. However, Colorado Senate Bill 1, as amended June 8, 1979, does not provide adequate enabling authority to establish an effective I/M program and cannot be unconditionally approved by EPA. The reasons for this are as follows:

1. Colorado Senate Bill 1 does not provide for a re-test after required adjustments are performed. Without such a re-test there is no way of confirming that the adjustments will be correctly performed, or if additional maintenance is required to bring a vehicle into compliance. There is also no provision for additional maintenance to ensure this compliance. Because of these deficiencies, it has not yet been shown that the emission reductions presumed in the plan will result.

2. Colorado Senate Bill 1 contains no emission standards nor does it provide authority to establish such standards to determine pass or fail of a motor vehicle. Without emission standards, an I/M program is not enforceable. Rather, the Bill directs the Commission to recommend standards to the legislature, which must approve such standards by legislation. Also Senate Bill 1 provides that all regulations adopted by the Commission expire on June 1 of the following year unless specifically approved by the legislature. Both these problems could impede the implementation and continued operation of an effective I/M program.

3. The program outlined in Senate Bill 1 may not be appropriate for 1981 and later model year vehicles since significant changes in automotive emission control technology will result in the partial or complete elimination of the adjustments specified in the Bill.

In addition to these deficiencies, the Colorado I/M program also lacks the following:

1. Schedules (milestones, dates, responsible agency) to implement the following I/M program elements; a public information program, certification of full legislative authority to carry out the program (including emission standards), initial notification of garages explaining the program and a schedule of implementation, initiation of construction of referee facilities, completion of construction of referee facilities, adoption of procedures for certification of inspection stations, completion of equipment purchase and delivery of equipment, initiation of hiring and training of inspectors or licensing of garages, initiation of introductory program (voluntary maintenance with either voluntary or mandatory inspection) if not previously initiated, initiation of mechanics training

and/or information program, initiation of mandatory inspection, initiation of mandatory repair for failed vehicles, and establishment of quality control procedures.

2. Provisions for recordkeeping, submittal of appropriate records by inspection facilities, and periodic and unannounced inspections of facilities.

3. A demonstration of and commitment to at least a 25% reduction in light duty vehicle exhaust emissions of carbon monoxide and hydrocarbons by December 31, 1987, compared to what the total emissions would be without the I/M program.

4. A commitment to implement and enforce the program.

Colorado Senate Bill 1 authorizes a study to compare the effectiveness of an emissions control program which requires motor vehicles to be inspected for exhaust gas emissions by means of an infrared analyzer with a program requiring adjustment of all motor vehicles to certain manufacturer's specifications in order for vehicles to obtain a certification of emission maintenance. The study will examine the use of exhaust gas emission standards designed to ensure no less than twenty, thirty, or forty percent of the vehicles fail such standards, and which requires vehicles which fail such inspection to be repaired to comply with such standards.

In addition, Senate Bill 1 contains a commitment that the study will be completed by January 1, 1980, and the general assembly will review the results of the study and pass appropriate additional legislation by March 1, 1980, to meet Act requirements.

EPA considers that the State is committed to adopting an acceptable program based on the results of the above study by March 1, 1980, and that this represents progress toward submitting a plan. It is clear, however, that the program passed by the legislature does not meet the requirements of the Clean Air Act and additional action by the legislature is essential. There was misunderstanding on the part of some of the legislators concerning whether EPA could approve the program established in Senate Bill 1. Thus, EPA considers that the State of Colorado has satisfied the condition for an extension of the deadline for certification of adequate legal authority for an I/M program to March 1, 1980 (44 FR 20377, footnote 27, April 4, 1979). Therefore, EPA conditionally approves this part of the SIP if adequate I/M legal authority is certified by March 1, 1980, and submitted to EPA, along with materials correcting the other identified deficiencies. The conditional approval is based on the State meeting the following schedule:

January 1, 1980–Senate Bill 1 study completed, submitted to legislature.
January 12, 1980–I/M included on list of Governor's Call Items for the 1980 legislative session.
February 1, 1980–Study results in the form of a draft final report reported to legislature.
February 1, 1980–Bill introduced in the legislature—copy submitted to EPA.
March 1, 1980–Submission to EPA of legislation signed into law by the Governor, as well as schedules (milestones, dates, responsible agency) to implement the I/M program and corrections to other noted deficiencies.

A notice soliciting public comment on the acceptability of this schedule appears elsewhere in today's **Federal Register**.

II. *Volatile Organic Compounds, Regulation Number 7.* As required by Sections 172 and 108 of the Act, stationary sources of volatile organic compounds (VOC's) in the Denver area must install RACT. EPA reviewed the Commission's Regulation 7 which provides for control of VOC's and found deficiencies in the Commission's approach to the control of VOC's which would not provide for RACT on existing sources. The specific deficiencies are:

1. The Commission has defined VOC as an organic compound having a vapor pressure of 0.1 pounds per square inch, or more. This definition exempts a significant number of compounds of VOC which contribute to ozone formation. EPA guidance recommends a limitation of 0.1 millimeters of mercury at standard conditions or a limitation based on the appropriate test procedures.

2. The controls for surface coating, cutback asphalt and degreasing do not represent RACT, since they are not equivalent to control measures supported by the emission control technology information summarized in EPA's Control Technique Guidelines (CTG) for VOC. Furthermore, the State failed to provide justification for deviating from the requirement for application of RACT.

3. The requirement for an approved balanced vapor-recovery system should specifically refer to the Colorado RACT design criteria.

4. The regulation provides an exemption for barometric-type condensors in use at petroleum refineries. The Division has not evaluated the effect of emission reduction on this vacuum producing system category.

Although EPA is not disapproving Regulation 7 because it exempts methyl chloroform and methylene chloride, the Agency is concerned about the environmental risks associated with their wide scale substitution and uncontrolled use as a means of compliance. Both these compounds have been identified as mutagenic, and methyl chloroform is suspected of contributing to the depletion of the stratospheric ozone layer. Exemptions of these compounds will encourage a major increase in their emissions, as an alternative to controlling trichloroethylene and other regulated solvents in metal degreasing operations, and should be avoided wherever possible.

On July 18, 1979, in a letter to EPA, the Commission committed to revising Regulation 7 by July 1, 1980. EPA's conditional approval of Regulation 7 is based upon the State meeting the following schedule:

November 1, 1979–Notice of public hearing and draft regulations. submitted to EPA.
January 3, 1980–Public hearing.
March 1, 1980–Adopt new regulation and submit to EPA.

EPA considers conditional approval appropriate since emissions from sources not covered by the existing Regulation 7 are minimal based on the State's emission inventory. A notice soliciting comment on the acceptability of this schedule appears elsewhere in today's **Federal Register**. The July 18, 1979, letter from the State also includes a commitment to revise Regulation 7 to be consistent with future CTG published by EPA.

III. *New Source Review Program, Regulation Number 3 (all nonattainment areas).* 1. The State statutory requirement for the automatic issuance of an Emission Permit when statutorily defined time limits have been exceeded is inconsistent with the requirements of Sections 110 and 173 of the Act. All permits issued for this reason will be invalid and EPA is disapproving that portion of the SIP.

2. The exemption for sources increasing emissions by less than 10% could exempt major modifications from new source review and therefore, it is inconsistent with Sections 171 and 172 of the Act. The exemption from offset requirements in nonattainment areas for sources with "actual" emissions less than the 50 tons per year, 1,000 pounds per day or 100 pounds per hour cutoffs must be revised to be "allowable" emissions.

The Governor's July 5, 1979, supplemental submittal commits the Commission to changing Regulation 3 so that these exemptions are consistent with the Act. EPA found Regulation 3 unclear in certain respects. Regulation 3 must be revised as follows:

a. As required by Section 173(1)(A), offsets, in addition to being greater than one-for-one, must represent reasonable further progress, when considered with the revised plan.

b. The definition of "source" and "facility" must be the same as defined by EPA's Emission Offset Interpretative Ruling (FR Vol. 44, January 16, 1979).

c. "Significant" as defined in Section (D)(3)(d) must be the same as defined by EPA's Emission Offset Interpretative Ruling, Section (II)(D).

EPA is conditionally approving Regulation 3 with the understanding that these changes will be made by March 1, 1980. A notice soliciting public comment on the acceptability of the March 1, 1980, deadline appears elsewhere in today's Federal Register.

Regional Planning Agencies' Portions of the SIP

Both the Denver (CO, ozone) and Larimer-Weld (CO) plans lack the detailed schedules for implementation and study of the transportation control measures identified in Section 108(f) of the Act.

The Governor's July 5, 1979, supplemental submittal included the Larimer-Weld transportation control measures schedules; and the Governor's July 27, 1979, supplemental submittal included the Denver transportation control measures schedules. EPA is proposing conditional approval of these schedules elsewhere in today's Federal Register.

Clarification by Commission

On July 5 and July 27, 1979, the Governor submitted final comments by the Commission on issues identified in EPA's proposal. This information helped clarify some of the issues. These clarifications are as follows:

I. *Total Suspended Particulates*—1. *Requested Extension for TSP Secondary Standard.* The State has requested from EPA an 18-month extension to July 1, 1980, for preparation of their secondary control strategy since attainment of the secondary standard will require emission reductions exceeding those achieved through the application of RACT.

EPA is granting Colorado's request for all five secondary nonattainment areas as provided for in Section 110(b) of the Act.

2. *Pueblo Stationary Source Controls.* The Pueblo plan relied upon emission reductions from stationary sources to demonstrate attainment. However, no legally enforceable emission reduction requirements or compliance schedules were included in the plan.

The Commission's supplementary submittal included information which showed that all the emission reductions projected between 1977 and 1982 have been achieved and all these sources are in compliance, except for CF&I Steel Corporation's fugitive emissions. A copy of CF&I compliance schedules was also included. With the submittal of these schedules, this deficiency has been corrected.

To be consistent with EPA's national policy of controlling steel mills to the degree necessary to meet ambient standards, Region VIII will require a demonstration through air quality modelling that the emissions from CF&I Steel Corporation do not violate the 24-hour TSP standards. EPA is conditionally approving the Pueblo plan provided that this 24-hour TSP attainment demonstration is submitted to EPA by January 1, 1980.

Elsewhere in today's Federal Register, EPA is soliciting public comment on the acceptability of this January 1, 1980, deadline.

II. *Expeditious Attainment.* Sections 172(a)(2) and 172(b)(11)(C) of the Act require the plan to demonstrate attainment of the ozone and CO standards as expeditiously as practicable, but no later than December 31, 1987, if a demonstration is made that attainment is not possible by December 31, 1982.

The Commission revised the request for extensions of the attainment dates to reflect the actual expected dates of attainment of the CO standard. This revised extension request submitted on July 5, 1979, seeks extension in CO attainment beyond the end of 1982 to December 31, 1985, in Colorado Springs, to December 31, 1986, in Fort Collins, and to December 31, 1984, in Greeley. EPA finds these revised dates acceptable.

III. *Denver Area Ozone and CO Attainment Demonstration.* The ambient ozone concentration predicted for Denver in 1987 was 0.127 ppm which exceeds the standard. Therefore, the measures needed to show attainment were not provided. Also, EPA considered the ozone improvement between 1982 and 1987 to lack adequate technical justification.

Computer model "compliance runs" for carbon monoxide and ozone have not yet been made due to the difficulties experienced by the Division in obtaining the necessary vehicle travel pattern data for 1982 and 1987. As a result, definitive RFP curves were not submitted to EPA. Instead, a preliminary RFP curve for CO attainment was provided which was based upon use of the "rollback" analysis technique. The preliminary RFP curve for ozone attainment reflected a commitment to attain the ozone standard by the end of 1987, rather than any calculation of actual reductions over time. It is recognized, however, that a "compliance run" and its attendant anaylses realistically could not be completed by July 1, 1979. In light of this situation, the Commission has prepared an interim ozone compliance assessment, using the linear rollback method.

Using the rollback technique, it is estimated that ozone concentrations of 0.137 ppm will be achieved in 1982, and of 0.119 ppm in 1987. EPA approves this attainment and reasonable further progress demonstration.

IV. *Private Motor Vehicle Use Restrictions.* The "No Drive Day" adopted by the Commission was unenforceable with no firm schedule for becoming mandatory. The Commission stated that they do not have the financial or manpower resources to implement a mandatory "No Drive Day" program, may not have the legal authority to do so, and may not be the most appropriate State agency for this responsibility. The Commission believes that a "No Drive Day" program is a reasonably available control measure for the Denver Region, and should be implemented as expeditiously as possible. It is the Commission's hope that a voluntary program will be successful and that there will be no need to seek the required legislative action for a mandatory program.

Accordingly, no credit has been taken in the SIP for any potential emission reducing effects of a possible "No Drive Day," and the concept has not been incorporated into the package of control strategies upon which carbon monoxide and ozone RFP and compliance have been determined. Therefore, EPA does not consider the "No Drive Day" to be an enforceable part of the SIP at this time. However, EPA will continue to monitor the State's reasonable further progress any may require implementation of this measure or equivalent measures if progress in not being made.

V. *Transportation Development Plan.* On July 27, 1979, in a letter to EPA, the Governor stated that the TDP was a portion of the SIP, and he emphasized the necessity for flexibility through annual updates. EPA is approving the TDP on the basis of the Governor's submittal. We understand that RTD and DRCOG may not be committed to carry out the TDP in its entirety if the required funds are not available. Unless the TDP portion of the SIP is revised, the implementation of the TDP will be enforceable as part of the SIP and projects included in the TDP must, at a minimum, receive priority in federal funding decisions. Furthermore, if the State intends to use the TDP to partially satisfy the requirements of Section 110(a)(3)(D) of the Act, all available Federal, State and local funds must be used, insofar as is necessary, to implement the TDP.

VI. *Socio-economic Analysis.* The socio-economic analysis required by Section 172(b)(9) of the Clean Air Act lacked the summary of the public comment on such analyses. The Commission has made available to EPA transcripts of these hearings. EPA has determined that this approach satisfies the 176(b)(9) requirements.

VII. *Conditional Approval of the Denver Area Plan.* The Commission conditionally approved the ozone and CO Denver plan because it did not consider the commitments in the plan to be adequate. Specifically, the condition required DRCOG to obtain resolutions from a majority of local governments in its jurisdiction adopting either the locally prepared plan or the adopted SIP.

At its meeting of May 24, 1979, the Commission changed the conditional approval of Denver to final approval. This action was taken following receipt from DRCOG of copies of Resolutions of Support of the revised SIP from thirty-three of the local governments in the Denver Region, representing 99 percent of the six-county areas's population.

VIII. *Expanded Public Transporation.* Section 110(a)(3)(D) of the Act requires that when an attainment date extension is approved the SIP must include a commitment to establish, expand, and improve public transportation measures to meet basic transportation needs as expeditiously as practicable, including a commitment to use necessary grants and State and local funds.

There was no commitment to submit plans for the Colorado Springs and Denver areas, which are being updated, and the Larimer-Weld area.

The Commission's supplementary information contains a commitment to submit the transit development plans and programs for Colorado Springs and Denver as they are revised and updated.

In the Larimer-Weld area, the first transit development plans are currently being prepared for Fort Collins and Greeley. It is anticipated that these plans will be completed by the fall of 1979 and adopted in early 1980. Following adoption of the plans, they will be submitted to EPA in support of the SIP.

Section 172(b)(11)(A)

On August 14, 1979, EPA received clarification from the Division that the Division had the authority under recently passed legislation (House Bill 1109) to adopt this program.

EPA is conditionally approving this part of the SIP provided the State adopts this program by March 1, 1980 elsewhere in today's **Federal Register.** EPA is requesting comments on the acceptability of the March 1, 1980, deadline.

Public Comments on Proposal

This section includes the relevant comments EPA received on the proposal and EPA's response.

Total Suspended Particulates, General

Several commentors suggested that the nonattainment designations should be based on respirable particulates only. EPA is currently reviewing the TSP standard and is considering the appropriateness of an inhalable particulate standard in the future. Until EPA promulgates changes to the existing standard, all nonattainment designations and nonattainment plans must be based on TSP.

Pueblo TSP

Several commentors disagreed with EPA and considered the emission reductions used in the control strategy to be legally enforceable. After receiving supplemental information from the Commission on July 5, 1979, which included CF&I's compliance schedule, EPA concurs that these emission reductions are legally enforceable.

One commentor suggested that Regulation 1, Part IV, "Emission Standards for Existing Iron and Steel Plant Operations," was not approvable since it did not provide for RACT on two uncontrolled sources of emissions (quenching and blast furnace casthouse). Omissions were also pointed out which made the regulation less stringent than the Federal/CF&I consent decree.

As discussed earlier in this notice, EPA is conditionally approving the Pueblo TSP plan if by January 1, 1980, the State submits a 24-hour TSP air quality modeling attainment demonstration to EPA. However, if attainment cannot be demonstrated with existing controls, EPA will require that controls be applied to sources at CF&I sufficient to demonstrate attainment and maintenance of standards as expeditiously as practicable. Furthermore, there is no requirement under Part D that State regulations be equivalent to emission limitations in a Federal consent decree as suggested by the commentor. However, the Federal consent decree will continue to be enforced.

Denver Area Ozone and CO

Several commentors found the ozone and CO plans deficient due to the failure to adopt all RACM. The commentors were not satisfied with the approach selected by DRCOG to evaluate the 18 transportation control measures required by section 108(f) of the Act. Some comments suggested control measures not provided for in Section 108(f).

Several commentors suggested that administrative procedures require EPA to propose action and provide the public an opportunity to comment on all materials submitted by the Commission to resolve deficiencies cited in EPA's proposal.

EPA agrees that final action cannot be taken on the detailed schedules submitted on July 27, 1979, and elsewhere in today's **Federal Register** is proposing action on these schedules and soliciting public comment on their acceptability. Conditional approval of the Denver CO and ozone plans is based on the State's timely submission of the necessary additional materials.

One commentor suggested that EPA disapproved Denver's reasonable further progress demonstration because the plan did not provide uniform emission reductions each year, and suggested that this rationale was not appropriate. EPA's proposed disapproval was based on the lack of incremental reductions rather than a lack of uniform emission reductions. The Act does not require uniform emission reductions each year.

There were several comments concerning the relationship of the TDP to the plan. DRCOG stated that only the goal of doubling ridership was to be part of the plan, RTD provided the opposite opinion, and other commentors found it unclear. As indicated in the Governor's July 27, 1979, letter to EPA, the TDP is part of the SIP.

Sanctions

Several commentors suggested that sections 176 (c) and (d) of the Act require that highway construction work in Denver be halted by withholding funds until the Denver SIP is approved. EPA disagrees with this comment and believes that, instead, Section 176(a) of the Act must be used to determine whether highway funds should be withheld. Under Section 176(a), highway funds available under Title 23, USC, may only be withheld if the EPA Administrator finds that the Governor has not made reasonable efforts to submit a plan which considers each of the elements required by Section 172. EPA believes the State has made a reasonable effort. However, as indicated elsewhere in this notice, if the State fails to meet any of the deadlines associated with this conditional approval action, EPA will immediately propose a finding under Section 176(a) and highway funds will be withheld.

Extensions

One commentor stated that failure to satisfy section 172(b)(11)(A) of the Act should not be reason for denial of the Governor's request for attainment date extensions. EPA agrees that the extension request should be granted when a demonstration shows attainment by 1982 is not possible even if Section 172(b)(11)(A) is fulfilled. However, in such a case, failure to satisfy the requirement would be grounds for disapproval of the SIP.

New Source Review Regulation Number 3

One commentor suggested that the automatic granting of a permit without affirmative action by the Division is consistent with the Act, because it only provides for a reasonable time within which the Division must act. EPA consider this a deficiency. However, Regulation Number 3 will be approved, except for the provision which automatically issues an Emission Permit because statutorily-defined time limits have been exceeded.

One commenter suggested that the Commission's definition of LAER is consistent with the Act. EPA has determined that the Commission's definition ("The most stringent emission limitation which is achieved in practice or can reasonably be expected to occur in practice by such class or category of source taking into consideration the pollutant which must be controlled.") is equivalent to Section 171(3) and approvable.

National Comments

One commentor submitted extensive comments which it requested be considered as part of the record for each state plan. Although these comments were submitted after the close of the comment period and many are not relevant to the Colorado plan, EPA has placed its response to those comments in the Regional Office docket and in the Public Information Reference Unit in Washington, D.C.

EPA Action

EPA approves the revised SIP for the areas described in the SUMMARY, because the SIP has satisfied all the Part D plan requirements for those nonattainment areas and has met the basic criteria for approving a plan revision under section 110(a)(3)(A) of the Act.

EPA conditionally approves the Denver ozone and the Denver, Colorado Springs, and the Larimer-Weld CO plans, which require I/M to demonstrate attainment provided the following requirements are met:

1. The Denver Area ozone and Denver Area, Colorado Springs and Larimer-Weld CO plans include an adequate vehicle emission control I/M program by March 1, 1980.
2. The Denver Area ozone plan provides for implementation of RACT for stationary sources of VOC's by March 1, 1980.
3. The Commission revises Regulation 3 to make it consistent with Section 173 of the Act by March 1, 1980.
4. The Larimer-Weld transportation control schedules are submitted by January 1, 1980.
5. The Denver transportation control schedules are revised to meet EPA requirements by January 1, 1980.
6. The Commission adopts a program to implement Section 172(b)(11)(A) of the Act by March 1, 1980.

EPA conditionally approves the Pueblo TSP plan provided the State demonstrates, by air quality modeling, that the emissions from CF&I Steel Corporation do not violate the 24-hour TSP standard.

EPA takes no action for areas where redesignations are being proposed in the Federal Register until a final decision is made.

A notice soliciting comments on the acceptability of these schedules appears elsewhere in today's **Federal Register**.

Because of the importance of the conditions presented above, in particular the importance of an effective I/M program in Colorado, EPA intends to implement the sanctions contained in Section 176(a) and 316 of the Act without delay should the State fail to comply with the conditions and deadlines. Therefore, EPA is taking the necessary preparatory steps now such as notifying relevant State and local officials and concerned Federal agencies including Federal Highway Administration and the Urban Mass Transportation Administration. The steps for applying these funding limitations are proposed in 44 FR 33473 (June 11, 1979), and 44 FR 38575 (July 2, 1979).

It is EPA's intention that if the State of Colorado fails to meet the above conditions, withholding of funds under Section 316 would begin not later than March 1, 1980, and EPA would simultaneously transmit a notice to the **Federal Register** proposing a finding under Section 176(a), which upon publication would prohibit award of EPA air grants or approval or funding of highway projects under Title 23, USC. If at any time prior to March 1, 1980, it becomes evident an acceptable I/M program is not likely to be enacted, this schedule for implementing Sections 176 and 316 will be accelerated.

If an effective I/M program is not adopted by March 1, 1980, the sanctions would be imposed in the Colorado Springs, Larimer-Weld, and Denver nonattainment areas. Due to potentially severe impacts resulting from the imposition of sanctions, it is vital that the effects be well understood. To that end, the following represents examples of projects and programs scheduled for funding in the near future which may be affected:

1. EPA Section 105 and 175 grants withheld from date of the violation of the conditional approval to the end of the fiscal year (all areas).
2. Sewage Treatment grants for the following projects may be affected:

Major projects	Step	Grant amount
a. Boulder	3	$8,625,000
b. Brighton	2	375,000
	3	5,625,000
c. Colorado Springs (Phase II)	2	1,125,000
	3	11,500,000
d. Denver Metro S.D.	2	2,090,000
(main plant)	3	30,000,000
e. Denver Metro S.D. (off-site solids)	3	24,000,000
f. Denver Metro S.D. (Sand Creek)	3	9,500,000
g. Denver Metro S.D. (Clear Creek)	2	300,000
h. Englewood/Littleton	2	250,000
	3	10,000,000
i. Fort Collins	3	952,500
j. Greeley (New Plant)	3	15,000,000
(Interceptor)	3	1,575,000
k. South Lakewood	3	1,335,000
l. Westminster	3	9,500,000
m. Weld County Tri-Area	3	800,000

3. Federal highway funds, except for safety, mass transit and transportation improvement projects related to air quality improvement or maintenance. According to EPA's and DOT's proposed Section 176(a) procedures, the latter exemption only includes transportation control measures included in the approved or promulgated SIP and projects which are specifically identified as air quality improvement projects in the Transportation Improvement Program.

If Colorado does not submit any of the materials needed to comply with the above conditions, EPA will publish a **Federal Register** notice at the expiration of the time limit for submittal ending the conditional approval and explaining that the Section 110(a)(2)(I) (44 FR 38583) July 2, 1979, restrictions are automatically imposed under the Act. These restrictions prohibit the construction of certain new major sources of air pollution in affected non-attainment areas. Also Section 105 and 175 grants may be withheld.

If the State submits the required additional documentation according to schedule EPA will publish a notice in the Federal Register announcing receipt of the material. The notice of receipt will also announce that the conditional approval is continued pending EPA's final action on the submission.

EPA will evaluate the State's submission to determine if the condition is fully met. After review is complete, a Federal Register notice will be published proposing or taking final action either to find the condition has been met and approve the plan, or to find the condition has not been met and disapprove the plan. If the plan is disapproved the section 110(a)(2)(I) sanctions will be in effect.

Elsewhere in today's Federal Register, deadlines by which conditions must be met are being proposed. Although public comment is solicited on the deadlines, and the deadlines may be changed in light of comment, the State remains bound by its commitment to meet the proposed deadlines unless they are changed.

The 1978 edition of 40 CFR Part 52 lists in the subpart for each state the applicable deadlines for attaining ambient standards (attainment dates) required by Section 110(a)(2)(A) of the Act. For each nonattainment area where a revised plan provides for attainment by the deadlines required by Section 172(a) of the Act, the new deadlines will be substituted on the attainment date charts. The earlier attainment dates under Section 110(a)(2)(A) will be referenced in a footnote to the charts. Sources subject to plan requirements and deadlines established under Section 110(a)(2)(A) prior to the 1977 Amendments remain obligated to comply with those requirements as well as with the new Section 172 plan requirements.

Congress established new deadlines under Section 172(a) to provide additional time for previously regulated sources to comply with new, more stringent requirements and to permit previously uncontrolled sources to comply with newly applicable emission limitations. If these new deadlines were permitted to supersede the deadlines established prior to the 1977 Amendments, sources that failed to comply with pre-1977 plan requirements by the earlier deadlines would improperly receive more time to comply with those requirements. Congress, however, intended that the new deadlines apply only to new, additional control requirements and not to earlier requirements. As stated by Congressman Paul Rogers in discussing the 1977 Amendments:

> Section 110(a)(2) of the Act made clear that each source had to meet its emission limits "as expeditiously as practicable" but not later than three years after the approval of a plan. This provision was not changed by the 1977 Amendments. It would be a perversion of clear Congressional intent to construe part D to authorize relaxation or delay of emission limits for particular sources. The added time for attainment of the national ambient air quality standards was provided, if necessary, because of the need to tighten emission limits or bring previously uncontrolled sources under control. Delays or relaxation of emission limits were not generally authorized or intended under part D. (123 Cong. Rec. H 11958, daily ed. November 1, 1977.)

To implement fully Congress' intention that sources remain subject to pre-existing plan requirements, sources cannot be granted variances extending compliance dates beyond attainment dates established prior to the 1977 Amendments. Such variances would impermissibly relax existing requirements beyond the applicable section 110(a)(2)(A) attainment date under the plan. Therefore, for requirements adopted before the 1977 Amendments, EPA cannot approve a compliance date extension beyond pre-existing 110(a)(2)(A) attainment dates, even though a Section 172 plan revision with a later attainment date has been approved.

However, in certain exceptional circumstances, extensions of compliance dates beyond a pre-existing attainment date are permitted. For example, if a Section 172 plan imposes new, more stringent control requirements that are incompatible with controls required to meet the pre-existing regulations, the pre-existing requirements and deadlines may be revised if a state makes a case-by-case demonstration that a relaxation or revocation is necessary. In addition, such an extension may be granted if it will not contribute to a violation of an ambient standard or a PSD increment.[1]

Under Executive Order 12044, EPA is required to judge whether a regulation is "significant" and therefore subject to the procedural requirements of the Order or whether it may follow other specialized development procedures. EPA labels these other regulations "specialized." I have reviewed this regulation and determined that it is a specialized regulation not subject to the procedural requirements of Executive Order 12044.

[1] See General Preamble for Proposed Rulemaking, 44 FR 20373–74 (April 4, 1979).

This notice of final rulemaking is issued under the authority of Section 110 of the Clean Air Act, as amended.

Dated: September 27, 1979

Douglas Costle,

Administrator.

Title 40, Part 52 of the Code of Federal Regulations is amended as follows:

Subpart G—Colorado

1. In § 52.320, paragraphs (c)(10)–(c)(15) are added as follows:

§ 52.320 Identification of plan.

* * * * *

(c) * * *

(10) On January 2, 1979, the Governor submitted the nonattainment area plan for all areas designated nonattainment as of March 3, 1978. EPA is taking no action on areas for which the Governor has requested redesignations (Larimer-Weld TSP and ozone; El Paso County ozone).

(11) Extension request for attainment of CO and O_3 was submitted by the Governor on January 5, 1979.

(12) On July 5, 1979, the governor submitted the Air Pollution Control Commission's final comment on our May 11, 1979, proposal. This included a clarification that the "No-Drive Day" was not part of the State Implementation Plan and transportation control measures schedules for Larimer-Weld.

(13) On July 18, 1979, the Commission committed to revising Regulation 7.

(14) On July 23, 1979, the Governor submitted House Bills 1109, 1090, and Senate Bill 1 as part of the plan.

(15) On July 27, 1979, the Governor submitted the Denver Regional Council of Governments schedules for implementing the transportation control strategies, and clarified that the Transportation Development Plan was part of the plan.

§ 52.321 [Amended]

2. Section 52.321 is amended by changing the heading "photochemical oxidants (hydrocarbon)" to "ozone".

3. In § 52.322, paragraphs (c), (d) and (e) are added as follows:

§ 52.322 Extensions.

* * * * *

(c) The Administrator hereby extends for 18 months (until July 1, 1980) the statutory time table for Colorado's plans for attainment and maintenance of the secondary standards for particulate matter in Denver, Grand Junction, Colorado Springs, Pueblo and Larimer-Weld nonattainment areas (40 CFR 81.306).

(d) The Administrator hereby extends to December 31, 1987, the attainment date for ozone in the Denver nonattainment area (40 CFR 81.306).

(e) The Administrator hereby extends to December 31, 1987 (Denver), December 31, 1985 (Colorado Springs), December 31, 1986 (Fort Collins), and December 31, 1984 (Greeley), the attainment dates for carbon monoxide in these nonattainment areas (40 CFR 81.306).

4. Section 52.323 is revised to read as follows:

§ 52.323 Approval status.

With the exceptions set forth in this subpart, the Administrator approves Colorado's plan for the attainment and maintenance of the national standards under Section 110 of the Clean Air Act. Furthermore, the Administrator finds that the plan satisifies all requirements of Part D, Title 1, of the Clean Air Act as amended in 1977, except as noted below.

5. In § 52.324 a new paragraph (c) is added as follows:

§ 52.324 Legal authority.

* * * * *

(c) The requirements of § 51.11(a)(4) of this chapter are not met since Regulation 3 provides that an emission permit be issued when statutorily-defined time limits have been exceeded.

6. Section 52.325 is revised as follows:

§ 52.325 Attainment dates for national standards.

The following table presents the latest dates by which the national standards are to be attained. These dates reflect the information presented in Colorado's plan, except where noted.

Air quality control region and nonattainment area	TSP		Pollutant SO_2		NO_2	CO	O_3
	Primary	Secondary	Primary	Secondary			
Pawnee Intrastate:							
a. Larimer-Weld Region	e	f	b	b	b	g/i	b
b. Remainder of AQCR	*c*	b	b	b	b	b	b
Metropolitan Denver:							
a. Denver Region	e	f	b	b	e	j	j
b. Grand Junction	e	f	b	b	b	b	b
c. Remainder of AQCR	*c*	b	b	b	b	d	b
Comanche Intrastate	b	b	b	b	b	b	b
San Isabel Intrastate:							
a. Colorado Springs	e	f	b	b	b	h	b
b. Pueblo	e	f	b	b	b	b	b
c. Remainder of AQCR	*c*	b	b	b	b	b	b
San Luis Intrastate	a	*c*	b	b	b	b	b
Grand Mesa Intrastate	*c*	*c*	b	b	b	b	b
Yampa Intrastate	b	b	b	b	b	b	b
Four Corners' Intrastate	*c*	*c*	b	b	b	b	b

Note.—Dates or footnotes which are *italic* are prescribed by the Administrator because the plan did not provide a specific date or the date provided was not acceptable.

a. Air quality levels presently below primary standards or area is unclassifiable.
b. Air quality levels presently below secondary standards or area is unclassifiable.
c. July 1975.
d. May 31, 1977.
e. December 31, 1982.
f. 18-month extension granted.
g. December 31, 1984 (Greeley).
h. December 31, 1985.
i. December 31, 1986 (Fort Collins).
j. December 31, 1987.

NOTE.—Sources subject to plan requirements and attainment dates established under Section 110(a)(2)(A) of the Act prior to the 1977 Clean Air Act Amendments remain obligated to comply with those requirements by the earlier deadlines. The earlier attainment dates are set out at 40 CFR 52.325.

7. Section 52.327 is revised as follows:

§ 52.327 Control strategy: Ozone.

(a) *Part D—Conditional Approval*—The Denver Plan is approved provided that the following conditions are satisfied:

(1) The plan includes an adequate vehicle emissions control inspection/maintenance program.

(2) The plan provides for implementation of reasonable available control technology on existing sources of volatile organic compounds.

(3) Regulation 3 is revised so that it is consistent with Section 173 of the Act.

(4) Section 172(b)(11)(A) programs adopted.

8. Section 52.328 is revised as follows:

§ 52.328 Control strategy: Carbon monoxide.

(a) *Part D—Conditional Approval*—The Denver, Colorado Springs and Larimer Weld plans are approved provided that the following conditions are satisfied:

(1) The plan includes an adequate vehicle emissions control inspection/maintenance program.

(2) Section 172(b)(11)(A) programs adopted.

9. Section 52.329 is revised as follows:

§ 52.329 Rules and regulations.

(a) *Part D—Conditional Approval*—Regulation 3 is approved as satisfying Part D requirements provided that the following conditions are satisfied:

(1) The exemption for sources increasing emission by less than 10% will be deleted.

(2) The exemption for sources with actual emissions less than the applicable cutoffs will be changed to allowable emissions.

(3) The State offset requirements are modified as follows:

(i) As required by Section 173(1)(A), offsets, in addition to being greater than one-for-one, must represent reasonable further progress, when considered with the revised plan.

(ii) The definition of "source" and "facility" are the same as defined by EPA's Emission Offset Interpretative Ruling (FR Vol. 44, January 16, 1979).

(iii) "Significant" as defined in Section (D)(3)(d) is the same as defined by EPA's Emission Offset Interpretative Ruling, Section (II)(D).

10. Section 52.330 is revised as follows:

§ 52.330 Control strategy: Total suspended particulates

(a) *Part D—Conditional Approval*—The Pueblo plan is approved conditioned upon the State demonstrating, by air quality modelling, attainment of the 24-hour standards, while considering the emissions from the Colorado Fuel and Iron steel mill.

[FR Doc. 79-31031 Filed 10-4-79; 8:45 am]

BILLING CODE 6560-01-M

FEDERAL MARITIME COMMISSION

46 CFR Part 503

[Managing Directive 79-4]

Public Information; Classification and Declassification of National Security Information and Material

AGENCY: Federal Maritime Commission.

ACTION: Implementing Directive; final rule.

SUMMARY: These regulations implement Executive Order 12065 dated June 28, 1978, published in the Federal Register on Monday, July 3, 1978, Part IV (43 FR 28949) and Information Security Oversight Office Directive No. 1 dated October 2, 1978, published in the Federal Register, Thursday, October 5, 1978, Part V (43 FR 46280) relating to the classification, downgrading, declassification and safeguarding of national security information.

EFFECTIVE DATE: August 29, 1979.

FOR FURTHER INFORMATION CONTACT: James K. Cooper, Director, Bureau of Enforcement (Security Officer), Federal Maritime Commission, Washington, D.C. 20573, telephone (202) 523-5860.

SUPPLEMENTARY INFORMATION: These regulations have been submitted to the Information Security Oversight Office in accordance with section 5-401 of Executive Order 12065. They replace Subpart F, § 503.51 through 503.56, Title 46 CFR, which Subpart is outdated by Executive Order 12065.

As these regulations are rules of agency organization, procedure or practice, notice and public procedure respecting them are not deemed necessary or appropriate under 5 U.S.C. 553(b)(A).

Therefore, pursuant to Executive Order 12065, Subpart F of 46 CFR Part 503 is revised to read as follows:

Subpart F—Classification and Declassification of National Security Information and Material

Authority: Executive Order 12065; Information Security Oversight Office Directive No. 1 dated October 2, 1978.

Source: Managing Directive 79-4 dated August 29, 1979.

§ 503.51 Purpose.

This Directive sets forth Commission procedures for the handling of national security information and material pursuant to Executive Order 12065 dated June 28, 1978 published in the **Federal Register** Monday, July 3, 1978, Part IV (43 FR 28949), and Information Security Oversight Directive No. 1 dated October 2, 1978 published in the **Federal Register** Thursday, October 5, 1978, Part V, (43 FR 46280). Commission employees may obtain copies of the Order and Directive from the Office of the Managing Director.

§ 503.52 Applicability.

This Directive applies to the handling of, and public access to, national security information and classified documents in the Commission's possession. Documents originated within this Commission but no longer in the Commission's possession will be handled by the agency having possession, or in accordance with the guidelines developed in consultation with the Archivist.

§ 503.53 Definitions.

As used in this Directive:

"Foreign government information" means either (a) information provided to the United States by a foreign government or international organization in the expectation, express or implied, that the information would be kept in confidence, or (b) information requiring confidentiality, produced by the United States under a written joint arrangement with a foreign government or international organization.

§ 503.54 Senior agency official.

The Director, Bureau of Enforcement, in his capacity as the Security Officer for the Commission, is designated the senior agency official responsible for conducting an oversight program to ensure effective implementation of Executive Order 12065.

§ 503.55 Oversight Committee.

An Oversight Committee is established, under the chairmanship of the Director, Bureau of Enforcement, with the following responsibilities:

(a) Establish a security education program to familiarize Commission and other personnel who have access to classified information with the provisions of Executive Order 12065, and encourage Commission personnel to challenge those classification decisions they believe to be improper.

(b) Establish controls to ensure that classified information is used, processed, stored, reproduced, and transmitted only under conditions that will provide adequate protection and prevent access by unauthorized persons.

(c) Act on all suggestions and complaints concerning Commission administration of its information security program.

(d) Establish and monitor policies and procedures within the Commission to ensure the orderly and effective declassification of Commission documents.

(e) Recommend to the Managing Director appropriate administrative action to correct abuse or violation of any provision of Executive Order 12065.

(f) Consider and decide other questions concerning classification and declassification that may be brought before it.

§ 503.56 Original classification.

(a) No Commission Member or employee has the authority to classify any Commission originated information.

(b) If a Commission Member or employee develops information that appears to require classification, the Member or employee shall immediately notify the Security Officer and protect the information accordingly.

(c) If the Security Officer believes the information warrants classification, it shall be sent to an agency with original classification authority over the subject matter, or to the Information Security Oversight Office, for review.

§ 503.57 Derivative classification.

Any document that includes paraphrases, restatements, or summaries of, or incorporates in new form, information that is already classified, shall be assigned the same level of classification as the source, unless the basic information has been so changed that no classification, or a lower classification than originally assigned, should be used.

§ 503.58 Declassification date on derivative documents.

(a) A document that derives its classification from information classified on or after December 1, 1978, shall be marked with the date or event assigned to that source information for its automatic declassification or for review of its continued need for classification.

(b) A document that derives its classification from information classified before December 1, 1978, shall be marked as follows:

(1) If the source has a declassification date or event 20 years or less from the date of its original classification, that date or event shall also be assigned to the derivative document.

(2) If the source has no declassification date or event, or has a date 20 years or more from the date of original classification, the derivative document shall be assigned a date for review for declassification 20 years from the date of original classification of the source information.

(3) If the source contains foreign government information having no date or event for declassification, or has a date 30 years or more from the date of original classification, the derivative document shall be assigned a date for review for declassification 30 years from the date of original classification of the source information.

(c) A derivative document that derives its classification from the approved use of the classification guide of another agency shall bear the declassification date required by the provisions of that classification guide, subject to the provisions of (a) and (b) of this section.

§ 503.59 General declassification policy.

(a) Effective December 1, 1978, dates for declassification assigned to documents generated in the Commission are derived from source documents in accordance with Executive Order 12065, Section 2-3. The Commission exercises declassification authority in accordance with sections 3-102 and 3-105 of the order, only over that information originally classified by the Commission under previous Executive Orders. Declassification authority may be exercised by the following Commission personnel:

Chairman
Managing Director
Security Officer

and such others as the Chairman may designate. Commission personnel may not declassify information originally classified by other agencies.

(b) Information originally classified by the Commission under Executive Order 11652 or prior orders shall be reviewed for declassification as it becomes 20 years old. Foreign government classified information, unless earlier declassified, shall be reviewed for declassification thirty years from its date of origin. Although the Commission does not now have classification authority, it had such authority prior to Executive Order 12065 and is responsible for issuing guidelines for systematic review for declassification in accordance with Section 3-402 of Executive Order 12065. The Commission's Managing Director is designated as the responsible official for the issuance of such guidelines.

§ 503.59a Requests for declassification.

(a) Requests for review for declassification of a document originally classified by the Commission may be made by any person, including Commission employees. The request shall be in writing, and shall be sent to the Director, Bureau of Enforcement, Federal Maritime Commission, Washington, D.C. 20573.

(b) The request shall describe the material sufficiently to enable the Commission to locate it. Requests with insufficient description of the material will be returned to the requester for further information.

(c) Commission employees who request declassification of a document orginally classified by the Commission may request their identity not be disclosed.

(d) If the request requires the provision of services by the Commission, fair and equitable fees may be charged under Title 5 of the Independent Offices Appropriation Act, 65 Stat. 290, 31 U.S.C. 483a.

§ 503.59b Commission action on declassification requests.

(a) Requests for declassification shall be acknowledged by the Commission within 15 days of the date of receipt of such requests.

(1) If the document was orginally classified by the Commission, the Managing Director shall decide whether the document should be classified, on the basis of the criteria of §503.59, the Commission guidelines for systematic review, and on the recommendation of the Commission office having custody of it.

(2) If the document was derivatively classified by the Commission or originally classified by another agency, the request and the document shall be forwarded to the agency with the original classification authority. The requester shall be notified of the referral, unless the originator of the information objects to the referral on the grounds that the association requires protection.

(3) If a document is declassified in its entirety, it may be released to the requester, unless withholding is otherwise warranted under applicable law. If a document or any part of it is not declassified, the Managing Director shall furnish the declassified portions to the requester, unless withholding is otherwise warranted under applicable law, along with a brief statement concerning the reasons for the denial of the remainder, and the right to appeal that decision to the Commission within 60 days.

(b) Commission employees shall not reveal the name of a Commission employee who requests anonymity under §503.59a(c) above.

§ 503.59c Appeals of denials of declassification requests.

(a) Within 60 days after the receipt of denial of a request for declassification, the requester may submit an appeal in writing to the Commission through the Secretary, Federal Maritime Commission, Washington, D.C. 20573. The appeal shall—

(1) Identify the document in the same manner in which it was identified in the original request;

(2) Indicate the dates of the request and denial, and the expressed basis for the denial; and

(3) State briefly why the document should be declassified.

(b) The Commission shall rule on the appeal within 30 days of receiving it.

(c) A determination by the Commission under paragraph (b) of this section is final and no further administrative appeal will be permitted. However, the requester may be informed that suggestions and complaints concerning the information security program prescribed by Executive Order 12065 may be submitted to the Director, Information Security Oversight Office, GSA (AT), Washington, D.C. 20405.

§ 503.59d Access by historical researchers.

(a) Persons outside the executive branch performing historical research may have access to classified information in the Commission's possession for the period requested (but not longer than 2 years unless renewed for an additional period of less than 2 years) if the Security Officer determines in writing that access to the information will be consistent with the interests of national security.

(b) The person seeking access to classified information must agree in writing:

(1) To be subject to a national agency check;

(2) To protect the classified information in accordance with the provisions of Executive Order 12065.

(3) Not to publish or otherwise reveal to unauthorized persons any classified information.

§ 503.59e Access by former Presidential appointees.

(a) Former Commission Members may have access to classified information or documents that they originated, reviewed, signed, or received while in public office.

(b) Upon the request of any former Member such information shall be reviewed by the Managing Director for declassification.

Effective date: August 29, 1979.

By the Commission.

Joseph C. Polking,

Assistant Secretary.

[FR Doc. 79-31029 Filed 10-4-79; 8:45 am]

BILLING CODE 6730-01-M

INTERSTATE COMMERCE COMMISSION

49 CFR Parts 1307 and 1310

[Ex Parte MC-88 (Sub-2)]

Detention of Motor Vehicles—Shipments of Uncrated New Furniture, Fixtures, and Appliances

AGENCY: Interstate Commerce Commission.

ACTION: Notification of Authority Citations.

SUMMARY: At 44 FR 33071-33072, June 8, 1979, the Interstate Commerce Commission adopted amendments to the regulations governing detention of vehicles. These amendments exempted certain shipments of uncrated or uncartoned new furniture, fixtures, or appliances from the detention rules. This document adds the authority citations under which those amendments were issued.

DATES: Exemption was effective on or before July 9, 1979.

FOR FURTHER INFORMATION CONTACT: Harvey Gobetz, (202) 275-7656.

SUPPLEMENTARY INFORMATION: The proper authority citations for the rule document published at 44 FR 33071-33072 which amended 49 CFR Parts 1307 and 1310 are as follows:

(49 U.S.C. 10321, 10704; 5 U.S.C. 553, 559)

Dated: September 28, 1979.

Agatha L. Mergenovich,

Secretary.

[FR Doc. 79-31027 Filed 10-4-79; 8:45 am]

BILLING CODE 7035-01-M

Proposed Rules

Federal Register
Vol. 44, No. 195
Friday, October 5, 1979

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

DEPARTMENT OF ACRICULTURE

Food and Nutrition Service

7 CFR Parts 272 and 273

[Amdt. No. 152]

Food Stamp Program; Procedures for Rounding Amounts in Calculating Net Monthly Income

AGENCY: Food and Nutrition Service, USDA.

ACTION: Proposed Rulemaking.

SUMMARY: This proposed rulemaking would revise the current procedure for rounding down to the next whole dollar in calculating net monthly income as a basis for determining financial eligibility and benefit levels under the Food Stamp Program. The Department proposes to authorize the State agency to use the standard rounding procedure or the rounding procedure in effect for that State's AFDC program. If the State AFDC program does not round eligibility computation at any point, the State agency would be required to round the final net income determination for food stamp purposes.

DATES: Comments must be received on or before November 19, 1979 to be assured of consideration.

ADDRESS: Comments should be submitted to: Claire Lipsman, Director, Program Development Division, Family Nutrition Programs, Food and Nutrition Service, USDA, Washington, D.C. 20250. A final rulemaking will be issued after considering the comments. All written comments, suggestions or objections will be open to public inspection at the office of the Food and Nutrition Service, USDA, during regular business hours (8:30 a.m. to 5:00 p.m, Monday through Friday) at 500 12th Street, SW, Washington, D.C., Room 658.

FOR FURTHER INFORMATION CONTACT: Susan McAndrew, Chief, Program Standards Branch, Program Development Division, Family Nutrition Programs, FNS, USDA, Washington, D.C. 20250. Telephone number: (202) 447-6535.

SUPPLEMENTARY INFORMATION: The Department published Federal regulations on October 17, 1978 (43 FR 47846) which implemented eligibility rules contained in the Food Stamp Act of 1977. Section 273.10(e)(1)(ii) of these regulations contained a procedure for rounding down to the next whole dollar in calculating net monthly income. According to this rule, State agencies are required to round down before and after each calculation, except for the computation of shelter costs. The cents are dropped from the total shelter costs only after the individual components are aggregated and just prior to determining the shelter deduction for the household's net monthly income.

The intent of the current rounding procedure was to simplify the income calculation and ensure that households would not be denied or have benefits reduced simply because a rounding procedure put them over an income level. While some State and local agencies expressed concern with the rounding procedure during the comment period, there was no consensus on an alternative procedure.

A new analysis of this rounding procedure shows that some households' net income is slightly understated, thereby adding to Food Stamp Program costs. In addition to reducing program costs, the Department is interested in matching processing procedures for the AFDC and Food Stamp Programs. Based on the current rounding methods, many States have been forced to develop two different calculation procedures.

The Department proposes to remedy this by authorizing State agencies to (1) round down in each income calculation that ends in 1 through 49 cents and round up for calculations that end in 50 through 99 cents, or (2) use that State's AFDC rounding procedure for each step in determining food stamp net income calculations. While there is no uniform rounding procedure for AFDC programs, the Department is satisfied that the individual State procedures will provide as close or closer approximation of net income than do current procedures. Certain States do not round at all for AFDC, but leave the cents in for the entire calculation. In that case, the Department proposes to require the State agency to round the final net income calculation down to the next whole dollar for values from 1 through 49 cents and up for values of 50 cents or greater. Otherwise, the AFDC procedure may be used for all of the net income and benefit level calculations including the intermediate steps for shelter cost components. This will make food stamp and AFDC income calculations more compatible, and will remove the administrative burden of having two different procedures.

This amendment has been classified "significant" and is being published under emergency procedures, as authorized by Executive Order 12044 and Secretary's Memorandum No. 1955, without a full 60-day comment period. It has been determined by Mr. Robert Greenstein, Administrator, Food and Nutrition Service that an emergency situation exists which warrants less than a full 60-day comment period on this proposal. A comment period of 45 rather than 60 days is needed so that if final regulations on rounding rules are adopted, they can be promulgated in time for States to implement in January 1980. Pub. L. 96-58 already requires States to implement new procedures for medical and shelter deductions by January 1, 1980. Many States are likely to find it far more efficient administratively to be able to implement any changes in rounding procedures at the same time they must begin calculating deductions in accordance with Pub. L. 96-58. Otherwise, States might have to apply two different rounding procedures to these deductible expenses, and recalculate benefits for these households.

Implementation

The Department proposes that State agencies initiate this rounding procedure for new applicants and recertifications no later than 90 days following the date final regulations are published, unless the State agency converts all or part of the caseload through a mass conversion as described below. Currently certified households would be converted using one of the following three procedures: (1) at the household's recertification; (2) during a desk review; or (3) at a point in time in which all households or all households in a certain category are converted, such as public assistance households or households in a particular project area. State agencies which conduct such mass conversions at a point in time would be required to implement this rulemaking no later than 120 days following publication of final regulations, provided that the mass conversion is conducted within those 120 days. We encourage comment on this proposal, particularly from any State agency wishing to conduct a mass conversion, to determine if 120 days is sufficient to prepare for such a conversion. State agencies utilizing either desk reviews or mass conversion to convert the caseload would be required to notify households in accordance with 273.12(e)(1).

The State agency would advise FNS before the conversion takes place which method of conversion will be used. The Department proposes that State agencies must complete the conversion process within one year following the implementation date of final regulations.

This proposal has been reviewed under the USDA criteria established to implement Executive Order 12044, "Improving Government Regulations," and has been classified "significant." An approved Draft Impact Analysis is available from Alberta Frost, Acting Deputy Administrator, Family Nutrition Programs, Food and Nutrition Service, USDA, Washington, D.C. 20250.

The Department proposes that Parts 272 and 273 of Chapter II, Title 7 Code of Federal Regulations be amended to read as follows:

PART 272—REQUIREMENTS FOR PARTICIPATING STATE AGENCIES

1. In § 272.1 a new paragraph (g)(8) is added:

§ 272.1 General terms and conditions.

* * * * *

(g) *Implementation.* * * *

(8) *Amendment 152.* The rounding procedure set forth in § 273.10(e) shall be in effect for new applications and recertifications within 90 days of publication of final regulations, unless the State agency conducts a mass computer conversion to the new rounding procedure as described below. The State agency shall have up to 12 months following the implementation date of final regulations to adopt for all food stamp applicants the rounding procedure that is chosen under § 273.10(e)(1)(ii). The State agency shall have a choice of the following three options in converting households that are already participating at the time the new rounding procedure goes into effect: (1) convert households at recertification; (2) convert households by conducting a desk review; or (3) convert households at a point in time in which all households or all households in a certain category are converted. For example, the State agency may convert all public assistance households or all households in a project area by computer. Such point in time mass conversions shall be conducted within 120 days following publication of final regulations. In any case, the State agency shall advise FNS regarding which rounding and caseload conversion procedure is chosen and when the conversion is completed.

* * * * *

PART 273—CERTIFICATION OF ELIGIBLE HOUSEHOLDS

2. In § 273.10 subparagraphs (e)(1)(ii) and (e)(2)(ii) are revised to read as follows:

§ 273.10 Determining household eligibility and benefit levels

* * * * *

(e) *Calculating net income and benefit levels.*—(1) *Net monthly income.*

* * * * *

(ii) In calculating net monthly income, the Stage agency shall use one of the following two procedures: (A) round down in each income and allotment calculation that ends in 1 through 49 cents and round up for calculations that end in 50 through 99 cents; or (B) apply the rounding procedure that is currently in effect for that State's Aid to Families with Dependent Children (AFDC) program. If the State AFDC program includes the cents in income calculations, the State agency may use the same procedure for food stamp income calculations.

* * * * *

(2) *Eligibility and benefits.*

* * * * *

(ii) The household's monthly allotment shall be equal to the thrifty food plan for the household's size reduced by 30 percent of the household's net monthly income as calculated in paragraph (e)(i) of this section. After multiplying the net income by 30 percent, the result shall be rounded using the rounding method selected in paragraph (e)(1)(ii) of this section prior to subtracting that amount from the thrifty food plan. However, if the State AFDC program does not round the income computation at any point, the State agency shall use standard rounding procedure. Final income amounts ending in 1 through 49 cents shall be rounded down while final amounts ending in 50 through 99 cents shall be rounded up. All eligible one- and two-person households shall receive a minimum monthly allotment of $10.

(91 Stat. 958 (7 U.S.C. 2011–2027).)

(Catalog of Federal Domestic Assistance Programs No. 10.551, Food Stamps.)

Dated: September 28, 1979.

Carol Tucker Foreman,

Assistant Secretary.

[FR Doc. 79–30818 Filed 10–4–79; 8:45 am]

BILLING CODE 3410-30-M

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

7 CFR Part 318

Hawaiian and Territorial Quarantine Notices; Hawaiian Fruits and Vegetables

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Proposed rule: Notice of further public hearings and extension of time for comment period.

SUMMARY: This action schedules further public hearings on the proposal to amend the Hawaiian fruits and vegetables rules and regulations. It also extends the period of time for comments on the proposal to November 9, 1979.

DATES: Comments on the proposed regulation must be received on or before November 9, 1979.

ADDRESS: Written comments should be submitted to the Hearing Officer, Plant Protection and Quarantine Programs, Animal and Plant Health Inspection Service, U.S. Department of Agriculture, Room 635, Federal Building, Hyattsville, MD 20782.

FOR FURTHER INFORMATION CONTACT: H. V. Autry, 301–436–8247.

SUPPLEMENTARY INFORMATION: On August 17, 1979, the Department published in the **Federal Register** (44 FR 48230–48234) a proposal to amend the Hawaiian fruits and vegetables rules and regulations relating to relieving and imposing restrictions regarding movement from Hawaii to other parts of the United States of certain fruits and vegetables. A 45-day comment period was provided in order that information for a decision could be obtained in sufficient time for the proposed regulation, if adopted, to be effective when the approved thick-skinned avocados are ready for harvest and shipment in November 1979. The comment period was scheduled to expire October 1, 1979. After publication of the proposal, the Department received requests from trade associations and organizations to extend the comment period to at least 60 days and to schedule additional hearings. The requests for extending the comment period were based on the assertions by the trade associations, organizations, and private individuals that the additional time was necessary in order to examine public records and prepare comments on the proposal. The requests for further public hearings were based on the assertions of the same parties that for the convenience of the affected public and to provide additional opportunity for public involvement, further public hearings should be held. These circumstances were considered sufficient justification for an extension of the time originally allotted for filing comments, and for the scheduling of further public hearings.

A notice was published in the **Federal Register** on September 20 and 21, 1979, which extended the comment period to October 20, 1979. In addition, that notice amended the previous **Federal Register** notice of August 17, 1979, by giving additional information on the conduct of the hearing proceedings and by citing the authority for the proposed action. The notice also announced a second hearing at New Orleans on October 3 and 4, 1979.

In accordance with the proposal to amend the Hawaiian fruits and vegetables rules and regulations published on August 17, 1979, as amended (44 FR 48230–48234 and 44 FR 54518), the first public hearing was held in Long Beach, California, on September 25 and 26, 1979, and the second public hearing was held in New Orleans on October 3 and 4, 1979.

The interest expressed on behalf of the public on this proposal has been much greater than anticipated. The comments received on the proposal have been substantial, informative, and constructive. The Department has also received additional requests for further public hearings in Hawaii. Therefore, in order to receive additional comments; for the convenience of the affected public; and to provide additional opportunity for public involvement, further public hearings have been scheduled. These hearings will take place Wednesday, October 24, in the Kamehameha Ballroom, Kona Surf Hotel, 78–128 Ehukai Street, Kailua-Kona, Hawaii 96740, (808) 322–3411, and Thursday, October 25 in the Alii Room, Napualani Hotel, 175 Paoakalani Avenue, Honolulu, Hawaii 96815, (808) 922–3861.

Also, additional time is being allowed for comments following the hearing. Accordingly, the comment period is being extended to November 9, 1979.

Each day's session of the hearing will commence at 10 a.m., and conclude at 5 p.m., local time, unless the presiding official otherwise specifies during the course of the hearing.

The hearing will be held before a representative of the Animal and Plant Health Inspection Service. At the hearing, a representative of the Animal and Plant Health Inspection Service will present a statement explaining the purpose and basis of the proposal. Any interested person may appear and be heard either in person or by attorney. Also, any interested person or his attorney will be afforded an opportunity to ask relevant questions concerning the proposal. Persons who wish to be heard are requested to register with the presiding officer prior to the public hearings. The pre-hearing registration will be conducted between 9 and 10 a.m. on each day. Those registered persons will be heard in the order of their registration. However, any other person who wishes to be heard or ask questions at the hearing will be afforded such opportunity, after the registered persons have presented their views. It is requested that quadruplicate copies of any written statements that are presented to be provided to the presiding officer at the hearing.

If the number of registered persons and other participants in attendance at the hearing warrants it, the presiding officer may, if it becomes necessary, limit the time for each presentation in order to allow everyone wishing to present a statement the opportunity to be heard.

Done at Washington, D.C., this 3rd day of October 1979.

T. G. Darling,

Acting Deputy Administrator, Plant Protection and Quarantine Programs, Animal and Plant Health Inspection Service.

[FR Doc. 79–31038 Filed 10–4–79; 8:45 am]
BILLING CODE 3410–34–M

Agricultural Stabilization and Conservation Service

7 CFR Part 729

[Amdt. 2]

Proposed Determinations Regarding Acreage Allotments, Marketing Quotas, and Poundage Quota for 1978 and Subsequent Crops of Peanuts

AGENCY: Agricultural Stabilization and Conservation Service, Department of Agriculture.

ACTION: Proposed rule.

SUMMARY: These proposed regulations set forth the rules for assessment of marketing quota penalties at a reduced rate when it is determined that a producer unintentionally or unknowingly marketed peanuts as quota peanuts in excess of the farm's poundage quota. The county ASC committee will determine if the excess marketings were unintentional or unknowingly made. This proposed rule also restricts the amount of quota a producer may carry over as undermarketings into the following year.

DATES: Comments must be received before November 5, 1979 in order to be sure of consideration.

ADDRESSES: Mail comments to the Director, Production Adjustment Division, ASCS, U.S. Department of Agriculture, 3630-South Building, P.O. Box 2415, Washington, D.C. 20013.

FOR FURTHER INFORMATION CONTACT: Paul P. Kume, Agricultural Stabilization and Conservation Service, Washington, D.C. 20013 (202) 447–4695.

SUPPLEMENTARY INFORMATION: The Food and Agricultural Act of 1977, amended the Agricultural Adjustment Act of 1938, as amended, and the Agricultural Act of 1949, as amended, to establish a two-tier peanut price support program applicable to the 1978 through 1981 crops. The 1978 peanut crop was the first to be marketed under the two-tier system. Extensive recordkeeping was required for the handling of the 1978 peanut crops, which consisted of quota and additional peanuts produced from the same farms. These reporting requirements were new and unfamiliar to both producers and handlers, and a large number of clerical and recordkeeping errors were made.

As a result of these errors, a substantial number of producers unintentionally and unknowingly overmarketed their poundage quotas. Section 359 of the Agricultural Adjustment Act of 1938, as amended, provides that the penalty for marketing quota peanuts from a farm in excess of the poundage quota established for the farm shall be 120 percent of the price support level for quota peanuts. Since the 1978 price support level for quota peanuts is $420 per ton, the marketing quota penalty is $504 per ton or 25.2 cents per pound. The regulations at 7 CFR § 729.46 require that any marketing quota penalty be assessed against both the producers and the handlers and both parties are jointly and severally liable for payment of the penalty.

Public Law 96–31 (93 Stat. 81, approved July 7, 1979), effective with the 1978 crop of peanuts, authorizes the Secretary of Agriculture to reduce any penalties assessed under section 359 of the 1938 Act, if the Secretary determines that the marketing of the peanuts for which the penalty is to be assessed was done unintentionally or unknowingly and that a reduction in the amount of the penalty would not impair the effective operation of the price support program for peanuts.

The Food and Agriculture Act of 1977 also amended Section 358 of the 1938 Act by adding a new subsection (o) providing as follows:

"* * * The poundage quota so determined, beginning with the 1979 crop for any farm, shall be increased by the number of pounds by which marketings of quota peanuts from the farm during the immediately preceding marketing year were less than the farm poundage quota: *Provided,* That total marketings shall not exceed actual production from the farm acreage allotment: *Provided further,* That the grower must have planted in such preceding marketing year that part of the farm allotment estimated on the basis of the farm yield to be sufficient to produce the total farm poundage quota * * *." *Provided further,* That if the total of all such increases in individual farm poundage quotas exceeds 10 per centum of the national poundage quota for the marketing year, the Secretary shall adjust such increases so that the total of all increases does not exceed 10 per centum of the national poundage quota.

Under the above provision of law, producers are allowed to carryover for one year undermarketings of quota peanuts. Undermarketings are defined as the amount by which the farm poundage quota exceeds marketings of quota peanuts from the farm. Accordingly, it is proposed that § 729.3 (11) be amended to clarify in the regulations this provision of the statute.

Proposed Rule

It is proposed that effective for the 1978 and subsequent crop of peanuts, the regulations at 7 CFR Part 729 be amended to read as follows: (1) Section 729.3 (LL)(1) is revised to read as follows:

§ 729.3 Definitions.

* * * * *

(LL) *Undermarketings.*

(1) *Actual undermarketings.* The pounds by which the effective farm poundage quota (minus any undermarketings from the preceding year which were added to such quota) exceeds the larger of (i) the total production of segregation 1 peanuts on the farm or, (ii) the total amount of quota peanuts which are marketed from the farm.

* * * * *

(2) Section 729.46 is amended by adding a new paragraph (d) which reads as follows:

§ 729.46 Penalty rate.

* * * * *

(d) *Penalty for unintentional error.* The penalty rate for the (i) 1978 crop of peanuts shall be 10 percent of the basic support price for quota peanuts which is determined to be $42 per ton or 2.1 cents per pound, (ii) 1979 crop of peanuts shall be 20 percent of the basic support price for quota peanuts which is determined to be $84 per ton or 4.2 cents per pound.

(3) Section 729.47(a)(1) is revised to read as follows:

§ 729.47 Peanuts on which penalty is due.

* * * * *

(1) The quantity of peanuts which is marketed or considered to be marketed from a farm for domestic edible use in excess of the farm poundage quota for the farm: *Provided,* That if the marketing of quota peanuts for which a penalty is to be assessed was done unintentionally or unknowingly by the producer and/or handler, the penalty shall be assessed at the reduced rate provided for in § 729.46(d), upon a determination by the county ASC committee that the error in excess marketing was unknowingly or unintentionally made and that a reduction in the amount of the penalty would not impair the effective operation of the price support program for peanuts. The provisions of this section shall be applicable only to producers or handlers who made a good faith effort to comply fully with the terms and conditions of the program.

* * * * *

(Secs. 301, 358, 358a, 359, 361–368, 373, 375, 377, 52 Stat. 38, as amended, 55 Stat. 88, as amended, 81 Stat. 658, 55 Stat. 90, as amended, 70 Stat. 206, as amended (7 U.S.C. 1301, 1358, 1358a, 1359, 1361–1368, 1372, 1373, 1375, 1377); Secs. 801, 802, 803, 804, 805, 806, 91 Stat. 944 (7 U.S.C. 1358, 1358a, 1359, 1373, 1377); and Sec. 359, 93 Stat. 81 (7 U.S.C. 1359 note.))

This amendment has been classified not significant and is being published under emergency procedures, as authorized by Executive Order 12044 and Secretary's Memorandum No. 1955, without a full 60-day comment period. It has been determined that an emergency situation exists which warrants less than a full 60-day comment period on this proposal because peanut producers have completed marketing their 1978 crop peanuts and are harvesting their 1979 crop. Peanut producers and handlers need to know the amount of penalties due for errors unknowingly or inadvertently made on the 1978 and 1979 crops.

The Production Adjustment Division (ASCS) is inviting comments on this propsed rule. All written submissions will be available for public inspection at the Office of the Director, Production Adjustment Division, Room 3630-South Building, 14th and Independence Avenue, S.W., Washington, D.C., during regular business hours, 8:15 a.m. until 4:45 p.m. (7 CFR 127(b)).

This proposal has been reviewed under the USDA criteria established to implement Executive Order 12044, "Improving Government Regulations". A determination has been made that this action should not be classified "significant" under those criteria. A Draft Impact Analysis has been prepared and is available from Thomas VonGarlem (ASCS) 202–447–7954.

Signed at Washington, D.C., on September 27, 1979.

Weldon B. Denny,

Acting Administrator, Agricultural Stabilization and Conservation Service.

[FR Doc. 79–31036 Filed 10–4–79; 8:45 am]

BILLING CODE 3410–05–M

Agricultural Marketing Service

7 CFR Part 981

Handling of Almonds Grown in California; Administrative Rules and Regulations

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Proposed rule.

SUMMARY: This rule proposes changes in the creditable advertising and quality control provisions of the administrative rules and regulations established under the Federal marketing order for California almonds. These changes are necessary to bring the provisions into conformity with current industry operating practices, and to aid handlers in selling increased supplies of almonds.

DATES: Written comments to this proposal must be received by October 22, 1979. Proposed effective date: November 1, 1979.

ADDRESSES: Written comments should be submitted in duplicate to the Hearing Clerk, Room 1077, South Building, U.S. Department of Agriculture, Washington, D.C. 20250. All written submissions will be available for public inspection at the office of the Hearing Clerk during business hours (7 CFR 1.27(b)).

FOR FURTHER INFORMATION CONTACT: William J. Higgins, (202) 447–5053.

SUPPLEMENTARY INFORMATION: Notice is given to amend Subpart—Administrative Rules and Regulations (7 CFR 981.401–981.474; 44 FR 30074, 31161) by revising §§ 981.441 and 981.442. This subpart is issued under the marketing agreement, as amended, and Order No. 981, as amended (7 CFR 981), regulating the handling of almonds grown in California. The marketing agreement and order are collectively referred to as the "order". The order is effective under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601-674). This action is based on a recommendation of the Almond Board of California.

The proposal is to revise § 981.441 to update two current provisions. Section 981.441 pertains to crediting a handler's assessment obligation for paid advertising which is authorized pursuant to § 981.41 in the order.

As provided in § 981.441(b), in order for a handler to receive credit for a paid advertisement, each advertisment must be published, broadcast, or displayed during the crop year for which credit is requested, except that a handler may expend a maximum of five percent of the total creditable advertising obligation (as of the June 30 redetermination report) in the subsequent July 1–September 1 period. In this case, the accompanying documentation must be filed with the Board no later than September 30. A handler utilizing this extension of time, however, has to certify to the Board, at time of redetermination, the planned expenditures during the extension period.

The five percent limit on such credit, however, is now seen as unnecessarily restricting handler operations. The sometimes large fluctuations in the size of the almond crop cause expansion or curtailment in advertising programs. Thus, it is desirable to provide that a greater portion of a handler's creditable advertising be carried over from one crop year to the next, in order to better sustain a fairly consistent ongoing advertising program. In this regard, the proposal is to amend § 981.441(b)(i) to permit that a maximum of twenty percent of the total handler creditable advertising obligation as of the June 30 redetermination report may be expended no later than December 31 of the subsequent crop year, and the related documentation filed with the Board no later than the following January 31.

Currently, § 981.441(e)(2) provides that credit not to exceed in total 10 percent of the creditable obligation for advertising in each crop year, would be granted a handler for media expenditures for advertising in 14 foreign countries. These countries are Great Britain, France, Italy, West Germany, Denmark, Belgium, Ireland, Luxembourg, The Netherlands, Sweden, Norway, Finland, Switzerland, and Japan. Credit may be allowed when claims are substantiated by applicable rate cards. The provisions of this section applicable to domestic advertising would apply to the crediting of advertising in these countries.

Given the importance to the almond industry of its export markets—which are expected to take approximately two-thirds of the 1979 California almond crop—the current ten percent limit is considered restrictive. Thus, the proposal is to amend § 981.441(e)(2) to increase this limit to twenty percent of a handler's total creditable advertising expenditures in the specified foreign countries.

Section 981.42 provides for each handler to cause to be determined, through the inspection agency, and at the handler's expense, the percent of inedible kernels in each variety of almonds received, and report this determination to the Board. The quantity of inedible kernels in each variety in excess of two percent of the kernel weight received, constitutes a weight obligation to be accumulated in the course of processing and shall be delivered to the Board, or Board accepted crushers, feed manufacturers, or feeders. Section 981.42 also authorizes the Board, with the approval of the Secretary, to change this percentage for any crop year, and to establish rules and regulations necessary and incidental to the administration of this provision, including, among other things, that the Board for good cause may waive portions of obligtions for those handlers not generating inedible material from such sources as blanching or manufacturing.

Section 981.442 specifies the procedures for implementing § 981.42. Currently, § 981.442(a)(1) provides for the sampling procedures for handlers to follow. For receipts of almonds at a handler's premises with mechanical sampling equipment and under contract providing for payment by the handler to the producer for sound meat content, samples shall be drawn by the handler in a manner acceptable to the Board and the inspection agency. The inspection agency shall make periodic checks of the mechanical sampling procedures. For all other receipts, including but not limited to field examination and purchase receipts, accumulations purchased for cash at the handler's door or from an accumulator, or almonds of the handler's own production, samples shall be drawn by or under the surveillance of the inspection agency. All samples shall be bagged and identified in a manner acceptable to the Board and the inspection agency. Each handler shall identify receipts according to the method of acquisition, and shall submit to the Board such reports of the quantity received by method of acquisition, as the Board may require.

As these provisions apply to a handler's own production, however, they do not now conform with industry practice. That is, handlers currently take safeguards to insure impartial sampling of almonds of their own production. Therefore, the proposal is to conform the requirements to current practices by revising § 981.442(a)(1) so that for such almonds, sampling shall be conducted or monitored by the inspection agency in a manner acceptable to the Board. Moreover, under the proposal, handlers would no longer be required to identify and report receipts according to the method of acquisition.

Section 981.442(a)(5) currently provides that the quantity of inedible kernels in each variety in excess of one and one-half percent of the kernel weight received, constitutes a handler's weight obligation to be delivered to the Board, or Board accepted crushers, feed manufacturers, or feeders. The industry now believes that a tolerence of two percent is more realistic given the existence now of more strict definitions of inedible kernels, and the economic hardship placed by the current tolerance on small handlers without almond product manufacturing facilities. Therefore, the proposal is to increase this tolerance to two percent.

This proposal has been reviewed under USDA criteria for implementing Executive Order 12044. It is being published with less than a 60-day comment period because the final regulation would apply to 1979 crop almonds, and handlers need to know of any rules changes as soon as possible. A determination has been made that this action should not be classified "significant". A Draft Impact Analysis is available from William J. Higgins, (202) 447-5053.

Therefore, the proposal is to amend Subpart—Administrative Rules and Regulations (7 CFR 981.441-981.474) as follows:

1. In § 981.441, paragraphs (b) and (e) are revised to read as follows:

§ 981.441 Crediting for paid advertising.

* * * * *

(b) Each advertisement must be published, broadcast, or displayed during the crop year for which credit is requested, except: (i) that a maximum of 20 percent of the total handler creditable advertising obligation as of the June 30 redetermination report may be expended no later than December 31 of the subsequent crop year, and documentation therefor filed with the

Board no later than the following January 31; and (ii) that a handler utilizing this extension certify to the Board, at time of redetermination, the planned expenditures during the extension period. The credit granted by the Board shall be that which is appropriate when compared to the applicable outlet rate published in the domestic or Canadian catalogs of Standard Rate and Data Service, or station or publisher or outdoor rate cards. In the case of claims for credit not covered by any such source, the Board shall grant the claim if it is consistent with rates for comparable outlets. For advertisements in countries other than the United States and Canada, paragraph (e) shall apply.

* * * * *

(e) Credit for media expenditures in a foreign country shall be granted:

* * * * *

(2) For a handler's media exenditures for brand advertising of almonds in the following countries: Great Britain, France, Italy, West Germany, Denmark, Beligium, Ireland, Luxembourg, The Netherlands, Sweden, Norway, Finland, Switzerland, and Japan, credit shall be allowed when claims are substantiated by applicable rate cards. The provisions of this section applicable to domestic advertising also shall apply to the crediting of advertising in these countries. The total of the foreign credit shall not exceed 20 percent of a handler's advertising assessment in each crop year.

* * * * *

2. In § 981.442(a) subparagraphs (1) and (4) are revised to read as follows:

§ 981.442 Quality control.

(a) *Incoming.* Pursuant to § 981.42(a), the quantity of inedible kernels in each variety of almonds received by a handler, including almonds of his own production, shall be determined and disposed of in accordance with the provisions of this paragraph.

(1) *Sampling.* Each handler shall cause a representative sample of almonds to be drawn from each lot, except lots of Peerles variety designated as bleaching stock, of any variety received. The sample shall be drawn before inedible kernels are removed from the lot, or the lot is processed or stored by the handler. For receipts at premises with mechanical sampling equipment and under contracts providing for payment by the handler to the producer for sound meat content, samples shall be drawn by the handler in a manner acceptable to the Board and the inspection agency. The inspection agency shall make periodic checks of the mechanical sampling procedures. For all other receipts, including but not limited to field examination and purchase receipts, accumulations purchased for cash at the handler's door or from an accumulator, or almonds of the handler's own productions, sampling shall be conducted or monitored by the inspection agency in a manner acceptable to the Board. All samples shall be bagged and identified in a manner acceptable to the Board and the inspection agency.

* * * * *

(4) *Disposition obligation.* The weight of inedible kernels in excess of two percent of the kernel weight reported to the Board of any variety received by a handler shall constitute the dispostion obligation. If a variety other than Peerless is used as bleaching stock, the weight so used may be reported to the Board and the disposition obligation for that variety reduced proportionately.

* * * * *

Dated: October 2, 1979.

D. S. Kuryloski,

Deputy Director, Fruit and Vegetable Division.

[FR Doc. 79-30946 Filed 10-4-79; 8:45 am]

BILLING CODE 3410-02-M

FEDERAL HOME LOAN BANK BOARD

12 CFR Ch. V

[No. 79-496]

Improving Government Regulations; Semiannual Agenda

Dated: September 26, 1979.

AGENCY: Federal Home Loan Bank Board.

ACTION: Semiannual Agenda.

SUMMARY: Pursuant to Board Resolution No. 79-364 (44 FR 37556; June 27, 1979), the Board is publishing an agenda of regulatory items, appropriate for publication under paragraph 5 of Resolution No. 79-364, which are currently under consideration or will be considered by the Board during the next six months.

FOR FURTHER INFORMATION: A staff contact for each item is identified with the regulatory description below.

SUPPLEMENTARY INFORMATION: The Board's Semiannual Agenda is divided into two sections. Section I describes major regulatory actions which have been proposed by the Board and are under active consideration. The comment period for each item is also indicated. Section II lists major regulatory projects which are actively being developed by agency staff for possible Board consideration within the next six months. The list is not all-inclusive, but is based on knowledge available at the present time.

Section I—Proposed Regulations

1. Branching of Federal Savings and Loan Associations

Action taken: In June 1979, by Resolution No. 79-339 (44 FR 36060), the Board proposed to consolidate and simplify procedures and requirements for the branching of Federal savings and loan associations. The proposed changes should streamline processing of branch applications, reduce the amount of information required for branch evaluation, and reduce costs to savings and loans and the Board. The comment period ended August 20, 1979.

Authority: The Home Owners' Loan Act of 1933, sec. 5, 48 Stat. 132, as amended; 12 U.S.C. section 1464.

Staff Contact: Lois G. Jacobs, Attorney, Office of General Counsel (202-377-6466).

2. Washington SMSA Branching

Action Taken: In June 1979, by Resolution No. 79-340 (44 FR 36057), the Board proposed a new regulation to allow reciprocal branching throughout the Washington, D.C.-Maryland-Virginia Standard Metropolitan Statistical Area ("SMSA") by Federal associations with any office located within the SMSA. The proposed regulation is intended to increase competition, enahance consumer services, and relieve the unique geographic constraints to D.C. branching. The comment period, which was to end October 15, 1979, will be extended to a date at least 30 days after the McFadden Study is submitted to Congress to give the public and the Board sufficient time to consider the related issues in light of the Study.

Authority: The Home Owners' Loan Act of 1933, sec. 5, 48 Stat. 132, as amended; 12 U.S.C. section 1464.

Staff Contact: Lois G. Jacobs, Attorney, Office of General Counsel (202-377-6466).

Reduction in Reporting Requirements

Action Taken: In June 1979, by Resolution No. 79-341 (44 FR 36398), the Board proposed to modify its requirements for reporting of financial data by member institutions.

The proposed changes would reduce required periodic reports by 19 percent, while allowing the Board to responsibly monitor the safe and sound operation of member institutions. The comment period ended August 20, 1979.

Authority: The Federal Home Loan Bank Act, sec. 17, 47 Stat. 736, as amended, 12 U.S.C. section 1437; The Home Owners' Loan Act of 1933, sec. 5, 48 Stat. 132, as amended, 12 U.S.C. section 1464.

Staff Contact: Nancy L. Feldman, Associate General Counsel (202-377-6440).

4. Loans Secured by Three- and Four-Family Dwellings

Action Taken: In June 1979, by Resolution No. 79-342 (44 FR 36056), the Board proposed to permit loans on three- and four-family dwellings to be made in amounts up to 90 percent of the value of the security property and up to $60,000 per dwelling. The proposed amendments are intended to increase opportunities for home ownership, especially in moderate-income neighborhoods in urban areas. The comment period ended August 20, 1979.

Authority: The Home Owners' Loan Act of 1933, sec. 5, 48 Stat. 132, as amended, 12 U.S.C. section 1464.

Staff Contact: John R. Hall, Attorney, Office of General Counsel (202-377-6445).

5. Collateralization of Bank Advances

Action Taken: In June 1979, by Resolution No. 79-343 (44 FR 36055), the Board proposed to ease requirements regarding collateralization of advances from Federal Home Loan Banks upon the security of home mortgages. The proposed modification should increase flexibility and efficiency, cut costs, and reduce paperwork, while maintaining protection of Bank security interests. The comment period ended August 20, 1979.

Authority: The Federal Home Loan Bank Act, sec. 17, 47 Stat. 736, as amended, 12 U.S.C. section 1437.

Staff Contacts: Daniel P. Chase, Office of the District Banks (202-377-6654) or Nancy L. Feldman, Associate General Counsel (202-377-6440).

6. Transactions With Affiliated Persons

Action Taken: In June 1979, by Resolution No. 79-344 (44 FR 36064), the Board proposed to modify its Conflict of Interest regulations to allow an FSLIC-insured institution to engage in real property transactions with affiliated persons of the institution if the transactions were found to be fair to, and in the best interests of, the insured institution. The regulation is needed to permit exceptions to the restriction on such transactions in cases that warrant it. The comment period ended August 20, 1979.

Authority: The National Housing Act, secs. 402, 403, 407, 48 Stat. 1256, 1257, 1260, as amended, 12 U.S.C. sections 1725, 1726, 1730.

Staff Contact: Kathleen E. Topelius, Attorney, Office of General Counsel (202-377-6444).

7. Automation of Consumer Complaint System

Action Taken: In June 1979, by Resolution No. 79-363 (44 FR 40406), the Board proposed to automate its consumer complaint system to improve complaint processing services and facilitate analysis of investigative problems and common consumer complaints. The comment period ended September 10, 1979.

Authority: The Privacy Act of 1974, Pub. L. 93-579, as amended; 5 U.S.C. section 552a.

Staff Contact: Lucy Hirshfeld Griffin, Director, Consumer Division, Office of Community Investment (202-377-6237).

8. Waiver of Penalties for Liquidity Deficiencies Caused by Withdrawals

Action Taken: In July 1979, by Resolution No. 79-380 (44 FR 41827), the Board proposed to amend its rules for the imposition of liquidity deficiency penalties to moderate the impact of net savings withdrawals on member institutions. The proposal recognizes that new forms of certificate accounts may result in the spread of withdrawals throughout the distribution periods and is fairer to member institutions than the present rule. The comment period ended September 15, 1979.

Authority: The National Housing Act, sec. 17, 47 Stat. 736, as amended; 12 U.S.C. section 1437; The Federal Home Loan Bank Act, sec. 5A, 83 Stat. 401; 12 U.S.C. section 1425a.

Staff Contacts: Dwight L. Arnall, Regional Supervisor, Department of Supervision, Office of District Banks (202-377-6522); or Nancy L. Feldman, Associate General Counsel (202-377-6440).

9. Management Interlocks

Action Taken: In July 1979, by Resolution No. 79-382 (44 FR 42217), the Federal Home Loan Bank Board, the Board of Governors of the Federal Reserve System, Comptroller of the Currency, Federal Deposit Insurance Corporation, and National Credit Union Administration, proposed amendments to recently-enacted regulations promulgated under the Depository Institutions Management Interlocks Act (1) to define "representative or nominee" under the Act, (2) to add provisions regarding grandfather rights and changes in circumstances, and (3) to determine whether a corporation is a management official under the Act. These amendments were proposed to supplement and clarify issues raised by the final Interlocks regulations. The comment period ended September 17, 1979.

Authority: Title II, Financial Institutions Regulatory and Interest Rate Control Act of 1978, Pub. L. 95-630, 12 U.S.C. section 3201.

Staff Contact: Kathleen E. Topelius, Attorney, Office of General Counsel (202-377-6444).

10. Securing Eurodollar Deposits

Action Taken: In July 1979, by Resolution No. 79-401 (44 FR 45635), the Board proposed to authorize Federal savings and loan associations to give security for marketable Eurodollar certificates of deposit of $100,000 or more and to grant FSLIC-insured institutions similar authority where authorized by state law. The proposed expanded authority would allow savings and loan associations to take advantage of international financing sources and pay a lower rate of interest than on some alternative financing sources. The comment period ends October 1, 1979.

Authority: The Home Owners' Loan Act of 1933, sec. 5, 48 Stat. 132, as amended; 12 U.S.C. section 1464. The National Housing Act, secs. 402, 403, 407, 48 Stat. 1256, 1257, 1260, as amended; 12 U.S.C. sections 1725, 1726, 1730.

Staff Contact: Douglas P. Faucette, Associate General Counsel (202-377-6410).

11. Supervisory Authority Over Insured Institutions

Action Taken: In July 1979, by Resolution No. 79-402 (44 FR 45175), the Board proposed regulations to implement title I of Pub. L. 95-630. The proposed amendments would revise Board regulations pertaining to (1) removals, suspensions, and prohibitions in cases where officers, directors or employees of FSLIC-insured institutions, or other persons participating in the institutions' affairs, are charged with or convicted of a crime; and (2) application of rules of practice and procedure regarding APA adjudicative proceedings to new powers included in title I. At the same time, the Board proposed to simplify and update some of its APA hearing rules and delete unnecessary regulatory provisions. The comment period closed August 31, 1979.

Authority: Pub. L. 95-630, title I, The Financial Institutions Regulatory and Interest Rate Control Act of 1978; The Home Owners' Loan Act of 1933, sec. 5, 48 Stat. 132, as amended, 12 U.S.C. section 1464; The National Housing Act, secs. 407 and 408, 48 Stat. 1260 and 1261, as amended, 12 U.S.C. sections 1730 and 1731.

Staff Contact: Larry M. Berkow, Associate General Counsel (202-377-6430).

12. Investment in HUD Section 8 Low-Income Housing

Action Taken: In August 1979, by Resolution No. 79-417 (44 FR 46477), the Board proposed to raise the maximum permissable loan-to-value ratio from 80% to 90% for conventional Section 8 loans on multifamily dwellings made by Federal savings and loan associations. Other proposed amendments would add safeguards to ensure sound lending practices regarding investment in Section 8 projects. The proposed liberalization of investment authority should provide additional incentive for the more than 4400 Federally-chartered and Federally-insured savings and loans institutions to meet their responsibilities under the Community Reinvestment Act and to increase their levels of community investment. The comment period ended September 7, 1979.

Authority: The Home Owners' Loan Act of 1933, sec. 5, 48 Stat. 132, as amended, 12 U.S.C. section 1464; National Housing Act, secs. 402, 403, 407, 48 Stat. 1256, 1257, 1260, as amended; 12 U.S.C. sections 1725, 1726, 1730.

Staff Contact: Lois G. Jacobs, Attorney, Office of General Counsel (202-377-6466).

Section II—Regulatory Items the Board May Consider During the Next 6 Months

1. Unfair or Deceptive Acts and Practices

Anticipated Action: Under Pub. L. 96-37, amendments to the Federal Trade Commission Act, the Board must, within 60 days after the effective date of an unfair trade practice rule promulgated by the FTC, promulgate a substantially similar rule for savings and loan institutions unless the Board determines that such practice is not unfair or deceptive as to savings and loans. Board staff is developing proposed regulations governing the preservation of consumer claims and defenses ("holder in due course" rule) in anticipation of FTC rules which may require regulatory action by the Board.

Authority: Section 18(f) of the Federal Trade Commission Act, as amended, Pub. L. 96-37, 15 U.S.C. section 57a(f).

Staff Contact: Patricia C. Trask, Attorney, Office of General Counsel (202-377-6442).

2. Simplification of Rules and Regulations for Insurance of Accounts

Anticipated Action: Board staff is developing provisions for nonsubstantive revision and simplification of the Rules and Regulations of Insurance of Accounts, the final phase of the Board's regulatory simplification project.

Authority: The National Housing Act, secs. 402, 403, 407, 48 Stat. 1256, 1257, 1260, as amended, 12 U.S.C. sections 1725, 1726, 1730.

Staff Contact: John R. Hall, Attorney, Office of General Counsel (202-377-6445).

3. Revisions to 12 CFR 563.33 of the Board's Conflict of Interest Regulations

Anticipated Action: In 1976, the Board adopted 12 CFR 563.33 which, *inter alia,* delineates guidelines regarding composition of the board of directors of an insured institution. Title II of Pub. L. 95-630, the Management Interlocks Act, and Board regulations recently issued thereunder prohibit certain interlocks among management officials, including directors, of depository institutions, depository holding companies, and affiliates of either. The Board's Conflict of Interest Regulations (12 CFR 563.33) also regulate the composition of Boards of Directors of Federally-insured institutions. Board staff is studying options for regulatory amendment to 12 CFR 563.33 to reconcile the differences between and reduce the complexities of compliance with the Act and Board regulations.

Authority: The National Housing Act, secs. 402, 403, 407, 48 Stat. 1256, 1257, 1260, as amended, 12 U.S.C. sections 1725, 1726, 1730.

Staff Contact: Kathleen E. Topelius, Attorney, Office of General Counsel (202-377-6444).

4. Rollover Mortgages

Anticipated Action: In December 1978, the Board, by Resolution No. 78-708 (43 FR 59336), authorized used of a variable rate mortgage ("VRM") by Federal savings and loan associations. The regulation as originally proposed (Board Resolution No. 78-428; 43 FR 33254-7; July 31, 1978) also would have authorized a "Rollover Mortgage" ("ROM"). The ROM as proposed was really a multi-year version of the VRM; it was therefore redesignated within the VRM regulation and the term "ROM" was eliminated. Board staff is now studying authorization of rollover, renegotiable, and/or renewable mortgages, as additional alternative methods of housing finance.

Authority: The Home Owners' Loan Act of 1933, sec. 5, 48 Stat. 132, as amended, 12 U.S.C. section 1464.

Staff Contacts: Richard Marcis, Deputy Director, Office of Economic Research (202-377-6752), and Lois G. Jacobs, Attorney, Office of the General Counsel (202-377-6466).

5. Revisions to Borrowing Regulations

Anticipated Action: Board staff is studying possible revisions to the borrowing regulations (12 CFR 545.24 and 563.8) which would 1) increase the allowable percentage of outside borrowings; 2) streamline application procedures and preapprove certain kinds of borrowings such as commercial paper and 3) require disclosure-investor protection for all public offerings. Revised borrowing authority would provide greater latitude and flexibility in the use of alternative sources of varying term funds at lower cost and a readily dependable market on a continuous basis.

Authority: The Home Owners' Loan Act of 1933, as amended, sec. 5, 48 Stat. 132, as amended, 12 U.S.C. section 1464.

Staff Contact: Douglas P. Faucette, Associate General Counsel (202-377-6410) and Maria Green, Attorney, Office of General Counsel (202-377-6427).

6. Change-in-Control Regulations

Anticipated Action: In February 1979, the Board, by Resolution No. 79-121 (44 FR 10500), issued temporary regulations implementing the Change in Savings and Loan Control Act of 1978, title VII of Pub. L. 95-630. The Board invited comments on the amendments through April 10, 1979. Board staff is now studying modifications to the temporary regulations based on the comments received and experience with the regulations.

Authority: Title VII, Financial Institutions Regulatory and Interest Rate Control Act of 1978; The National Housing Act, sec. 407, 48 Stat. 1260, as amended, 12 U.S.C. section 1730.

Staff Contact: Richard L. Little, Assistant General Counsel (202-377-6452).

7. Amendments to Holding Company Regulations

Anticipated Action: On January 10, 1979, the Board held an informal public hearing to elicit the views and comments of interested parties on possible revisions to Board regulations (12 CFR Part 583 *et. seq.*) promulgated under the Savings and Loan Holding Company Act. The present holding company regulatory program has been in operation for ten years without major revision or review. Based on oral and written comments received in response to the public hearing and continuous staff evaluation, Board staff is studying revisions to the holding company regulations.

Authority: The Savings and Loan Holding Company Act, sec. 407a, 48 Stat. 1260a, as amended, 12 U.S.C. section 1730a.

Staff Contact: William M. Herrick, Attorney, Office of General Counsel (202-377-6416).

8. Payment of Attorney Fees by Home Borrowers

Anticipated Action: 12 CFR 563.35(d) permits an insured lender to require a home borrower to reimburse, or to pay directly, attorney fees incurred by the lender in processing and closing a home loan. The Public Citizen Litigation Group, *et. al.*, has filed a petition requesting the Board to amend this regulation to give the borrower certain options in attorney selection and provide additional consumer safeguards. Board staff is reviewing the merits of the suggestions in light of experience under the present regulations to remedy possible consumer inequities.

Authority: The National Housing Act, secs. 402, 403, 407, 48 Stat. 1256, 1257, 1260, as amended, 12 U.S.C. sections 1725, 1726, 1730.

Staff Contact: Kathleen E. Topelius, Attorney, Office of General Counsel (202-377-6444).

9. Revision of the Loan Application Register

Anticipated Action: By Board Resolution 78-302 (43 FR 22332; May 25, 1978), the Board established a new monitoring system, a loan application register, for fair lending enforcement and analysis. The Board indicated at that time that the Register would be studied and revised as necessary. Board staff has been evaluating the usefulness of data now being collected and is considering revisions to the Register based on such evaluation. The contemplated revisions would further implement provisions of the Board's equal rights settlement agreement of 1977, and facilitate enforcement of the Board's fair lending responsibilities.

Authority: The Community Reinvestment Act, title VIII, Pub. L. 95-128, 91 Stat. 1147 (12 U.S.C. section 2901); The Equal Credit Opportunity Act, title VII, Pub. L. 93-495 (15 U.S.C. section 1691); The Fair Housing Act, title VIII, Pub. L. 90-284, 82 Stat. 81 (42 U.S.C. sections 3601-3619); 16 Stat. 144, 14 Stat. 27 (42 U.S.C. section 1981); The Home Owners' Loan Act of 1933, sec. 5, 48 Stat. 132, as amended, 12 U.S.C. section 1464; The National Housing Act, secs. 402, 403, 407, 48 Stat. 1256, 1257, 1260, as amended, 12 U.S.C. sections 1725, 1726, 1730; The Federal Home Loan Bank Act, sec. 17, 47 Stat. 736, as amended, 12 U.S.C. section 1437.

Staff Contacts: Patricia C. Trask, Attorney, Office of General Counsel (202-377-6442).

(Reorg. Plan No. 3 of 1947, 12 FR 4981, 3 CFR, 1943-48 Comp., 1071)

By the Federal Home Loan Bank Board.

J. J. Finn,

Secretary.

[FR Doc. 79-30945 Filed 10-4-79; 8:45 am]

BILLING CODE 6720-01-M

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE

Food and Drug Administration

21 CFR Part 166

[Docket No. 78P-0254]

Labeling of Margarine; Proposed Deletion

AGENCY: Food and Drug Administration.

ACTION: Proposed rule.

SUMMARY: This document proposes to amend the margarine labeling regulation which set forth the manner in which the ingredients in oleomargarine or margarine should be declared. These provisions are unnecessary because the standard of identity for margarine requires that all optional ingredients be declared as required by the applicable sections of the food labeling regulations. The purpose of this document is to eliminate duplications and inconsistencies in the ingredient labeling requirements for margarine.

DATE: Comments by December 4, 1979.

ADDRESS: Written comments to the Hearing Clerk (HFA-305), Food and Drug Administration, Rm. 4-65, 5600 Fishers Lane, Rockville, MD 20857.

FOR FURTHER INFORMATION CONTACT: Howard N. Pippin, Bureau of Foods (HFF-312), Food and Drug Administration, Department of Health, Education, and Welfare, 200 C St. SW., Washington, D.C. 20204, 202-245-3092.

SUPPLEMENTARY INFORMATION: The National Association of Margarine Manufacturers (NAMM) submitted a petition dated July 12, 1978, requesting that the Food and Drug Administration (FDA) amend the margarine labeling regulation (21 CFR 166.40(b)(1) and (2)) by deleting the term the "hardened" and the example "hardened cottonseed oil" where they appear. The grounds for this request were that the use of term "hardened" is inconsistent with the general labeling regulation of March 28, 1978 (43 FR 12856), which does not allow the use of the term "hardened."

FDA agrees with NAMM's contention that there are inconsistencies between the margarine labeling regulation and the general labeling regulation under Part 101, as referenced in the standard of identity for margarine regulation (21 CFR 166.110). However, FDA does not believe the inconsistencies and duplications can be completely eliminated by deleting the term "hardened" and the example "hardened cottonseed oil."

Therefore, FDA, based in part on NAMM's petition, proposes to amend § 166.40 by deleting paragraph (b) (1) through (10). This action is both necessary and appropriate because of its inconsistencies with or its duplications of the requirement for the margarine standard of identity which specifies that "each of the optional ingredients shall be declared on the label as required by the applicable section of Part 101." The reasons for expanding NAMM's petition to delete § 166.40(b) (1) through (10) are as follows:

Paragraph (b) (1) and (2) has been interpreted as permitting all fats or oils in a margarine to be listed together in the ingredient statement. FDA advises that margarine is required to be labeled in accordance with the requirements of Part 101, as referenced in the standard of identity for margarine. This means that the fats or oils in margarine are entitled to be labeled in accordance with § 101.4(b)(14) which permits a food, such as margarine, in which the combined weight of all the fat or oil ingredients constitutes the predominant ingredient, to list such fats or oils together in a specified manner as an alternative to listing all ingredients in strict order of predominance.

Thus, § 101.4(b)(14) permits a margarine containing a blend of fats or oils to be declared as a specific blend in the ingredient statement such as "vegetable oil blend," followed by the common or usual names of the fats and/or oils in parentheses. The fats and/or oils listed in parentheses are required to appear in descending order of predominance.

This labeling closely approximates the current labeling which may appear on some margarine products. However, § 166.40 does not require or provide for the parenthetical listing of the fats or oils. Therefore, with the deletion of § 166.40(b) (1) and (2), those manufacturers who are labeling their margarine on the basis of the current interpretation of § 166.40(b) (1) and (2) may find that revisions in their labels are necessary in order to comply with § 101.4(b)(14). Any such revisions in labels resulting from this proposal will involve adding a statement of the type of blend and enclosing the already listed fats or oils in parentheses. For example, if in accordance with the current interpretation the label of a margarine now lists four items in the ingredient statement, the first three ingredients being vegetable oils and the fourth a nonfat ingredient that is present in a quantity greater than one of the oil ingredients, the effect of the proposal will be to require that the oil ingredients be listed together in order of predominance as permitted in § 101.4(b)(14), e.g., "vegetable oil blend (corn oil, safflower oil, cotton seed oil)", followed by the nonfat ingredient, e.g., "salt", or that all the ingredients be placed in correct order of predominance, e.g., "corn oil, safflower oil, salt, cotton seed oil".

Section 166.40(b) (3), (4), (5), (8), and (9) requires the declaration of specific optional ingredients on the label. These requirements are unnecessary because all ingredients in the standard of identity for margarine are optional and are required to be placed on the label in accordance with the appropriate section in Part 101.

Section 166.40(b)(6) requires that the optional ingredient vitamin A be declared as "Vitamin A added" or "with added Vitamin A." The standard of identity for margarine does not require a statement of the addition of Vitamin A. However, because the form in which Vitamin A may be added is optional, the specific form used must be listed in the ingredient statement in accordance with the appropriate section of Part 101.

Section 166.40(b)(7) requires that the optional ingredient Vitamin D be declared as "Vitamin D added" or "with added Vitamin D." The standard of identity for margarine (§ 16.110(b)(1)) recognizes Vitamin D as an optional ingredient to be listed on the label as required by Part 101. Part 101 does not require that the label bear the statement concerning the addition of Vitamin D, but does require that Vitamin D, when present, be declared in the ingredient statement by its specific common or usual name, and that the label bear nutrition labeling.

Section 166.40(b)(10) deals with the conspicuousness and legibility requirements of section 403(f) of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 343(f)). It is unnecessary because all of the declarations of ingredients required by the standard of identity are subject to the requirements set forth in §§ 101.2, 101.15, and 101.105(h) (1) and (2).

Because labeling under the interpretation of § 166.40 closely approximates the labeling provisions of § 101.4, no wholesale changes in margarine labels as a result of this proposal will be necessary; therefore, this proposal allows existing margarine label inventories to be used until exhausted.

The agency proposes that the effective date of any final regulation ruling on this proposal be July 1, 1981.

Under § 25.1(f)(12) (21 CFR 25.1(f)(12)), FDA has determined that this proposed action will have no significant effect on the environment. Therefore, no environmental impact statement is required.

Therefore, under the Federal Food, Drug, and Cosmetic Act (secs. 401, 701(e), 52 Stat. 1046, 70 Stat. 919 as amended (21 U.S.C. 341, 371(e))) and under authority delegated to the Commissioner of Food and Drugs (21 CFR 5.1), it is proposed that Part 166 be amended by revising § 166.40(b) to read as follows:

§ 166.40 Labeling of margarine.

* * * * *

(b) The identity standard for oleomargarine or margarine applies to both the uncolored and the colored article.

* * * * *

Interested persons may, on or before December 4, 1979 submit to the Hearing Clerk (HFA-305), Food and Drug Administration, Rm. 4-65, 5600 Fishers Lane, Rockville, MD 20857, written comments regarding this proposal. Four copies of any comments are to be submitted, except that individuals may submit one copy. Comments are to be identified with the Hearing Clerk docket number found in brackets in the heading of this document. Received comments may be seen in the above office between 9 a.m. and 4 p.m., Monday through Friday.

In accordance with Executive Order 12044, the economic effects of this proposal have been carefully analyzed, and it has been determined that the proposed rulemaking does not involve major economic consequences as defined by that order. A copy of the regulatory analysis assessment supporting this determination is on file with the Hearing Clerk, Food and Drug Administration.

Dated: September 28, 1979.

Joseph P. Hile,

Associate Commissioner for Regulatory Affairs.

[FR Doc. 79-30926 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-03-M

21 CFR Part 1020

[Docket No. 79N-0148]

Diagnostic X-Ray Systems and Their Major Components Amendments to Performance Standard; Correction

AGENCY: Food and Drug Administration.

ACTION: Correction.

SUMMARY: In FR Doc. 79-23641 appearing on page 45645 in the **Federal Register** of Friday, August 3, 1979, § 1020.30(n) is corrected by changing the first and second sentences to read as follows:

§ 1020.30 Diagnostic x-ray systems and their major components.

* * * * *

(n) * * * The aluminum equivalent of each of the items listed in Table II, which are used between the patient and image receptor, shall not exceed the indicated limits. Compliance shall be determined by x-ray measurements made at a potential of 100 kilovolts peak and with an x-ray beam that has a half-value layer of 2.7 millimeters of aluminum. * * *

EFFECTIVE DATE: October 5, 1979.

FOR FURTHER INFORMATION CONTACT: Robert Phillips, Bureau of Radiological Health (HFX-460), Food and Drug Administration, Department of Health, Education, and Welfare, 5600 Fishers Lane, Rockville, MD 20857, 301-443-3426.

Dated: September 28, 1979.

William F. Randolph,

Acting Associate Commissioner for Regulatory Affairs.

[FR Doc. 79-30924 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-03-M

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 1

Income Tax; Reasonable Funding Methods

AGENCY: Internal Revenue Service, Treasury.

ACTION: Notice of proposed rulemaking.

SUMMARY: This document contains proposed regulations relating to reasonable funding methods. Changes to the applicable tax law were made by the Employee Retirement Income Security Act of 1974. The regulations would provide the public with guidance needed to comply with that Act and would affect defined benefit pension plans.

DATES: Written comments and requests for public hearing must be delivered or mailed by December 4, 1979. The amendments are proposed to be effective prospectively. However, they would contain a transition rule generally for plan years beginning after 1975, but earlier (or later) in the case of some plans as provided for meeting the minimum funding requirements under the Employee Retirement Income Security Act of 1974.

ADDRESS: Send comments and requests for a public hearing to: Commissioner of Internal Revenue, Attention: CC:LR:T, Washington, D.C. 20224.

FOR FURTHER INFORMATION CONTACT: Thomas F. Rogan of the Employee Plans and Exempt Organizations Division, Office of the Chief Counsel, Internal Revenue Service, 1111 Constitution Avenue, NW., Washington, D.C. 20224 (Attention: CC:LR:T) (202-566-3544).

SUPPLEMENTARY INFORMATION:

Background

This document contains proposed amendments to the Income Tax Regulations (26 CFR Part 1) under section 412(c)(3) of the Internal Revenue Code of 1954. These amendments are proposed to conform the regulations to sections 3(31) and 1013(a) of the Employee Retirement Income Security Act of 1974 (ERISA) (88 Stat. 837, 914) and are to be issued under the authority of section 3(31) of ERISA (88 Stat. 837; 29 U.S.C. 1002) and section 7805 of the Internal Revenue Code of 1954 (68A Stat. 917; 26 U.S.C. 7805.)

The proposed regulations contained in this document will also apply for purposes of section 302(c)(3) of ERISA (88 Stat. 871).

Section 412 of the Internal Revenue Code of 1954, contained in section 1013 of ERISA, provides minimum funding requirements with respect to certain pension plans. To meet these requirements, section 412(c)(3) requires that a reasonable funding method must be used. Section 3(31) of ERISA lists certain acceptable actuarial cost methods and directs the Secretary of Treasury "to further define acceptable actuarial cost methods."

Purpose and Approach

The purpose of this regulation in further defining acceptable actuarial cost methods as defined by section 3(31) of ERISA is to assure with reasonable certainty the equitable character and financial soundness of plans that must meet the minimum funding requirements. The regulation would define the outer limits of acceptability for funding methods by balancing conflicting interests. On the one hand, there is the need to foster soundness and stability among plans by preventing underfunding. On the other hand, there is the need to limit abuses of preferential tax treatment for plans by preventing overfunding.

To propose a single actuarial method for use by all plans would be inappropriate. A wide range of possible methods would serve the general purposes of this regulation. Therefore, by establishing the outer limits of acceptability, this regulation would identify an acceptable range within which numerous methods would fall.

A plan's actuary would continue to be responsible for applying these methods in a reasonable manner under the particular facts and circumstances of each case. However, generally accepted actuarial principles apply to other types of plans in addition to those subject to the minimum funding requirements. Therefore, to provide uniformity and certainty in measuring the actuary's judgment as exercised specifically with respect to plans subject to the minimum funding requirements, this regulation would impose certain limitations on the exercise fo the actuary's responsibility.

Underlying Principle

Underlying the proposed regulation would be the basic principle that, within the context of the requirements of ERISA, a funding method is not acceptable unless it rationally apportions the overall costs of a plan among the years during which the plan is maintained. However, it would appear on balance that some methods normally pose a high risk to the soundness and stability of a plan. An example of such a method would be one that requires a rapidly accelerating rate of contributions. The stability of required contributions under such a method would rest in part on the steady influx of new participants and on the likelihood that future salary scale adjustments would not be required.

It appears to be impossible to formulate with precision a rule that anticipates the circumstances under which such a method would not adversely affect a plan's soundness and stability. Therefore, the regulation would impose a rule generally proscribing such a particular method.

Specific Rules

This regulation contains specific rules for determining what is a reasonable funding method for an ongoing plan. The basic funding formula under the regulation reflects the general actuarial principle that the value of what goes into a plan must equal the value of what comes out of a plan. For a funding method to be reasonable, the basic formula must be met at all times.

The regulation also contains rules for determining normal cost. Among these rules are provisions relating to the use of salary scale and multiple accrual rates. These provisions would apply most commonly to a unit credit method.

Paragraph (c)(3)(i) of the proposed regulation in effect prohibits a taxpayer from contending that, merely because the unit credit funding method is being used, a salary scale assumption is inappropriate. This does not mean, however, that the use of a salary scale assumption will be required in all such cases. The need for a salary assumption will be determined on the basis of the reasonableness of all of the plan's assumptions viewed in the aggregate.

Paragraph (c)(4) of the proposed regulation would apply to the allocation of liabilities of final average pay plans funded under the unit credit cost method. To apply the unit credit method to a final average pay plan, the total projected benefit must be allocated among the plan years. The proposed regulation would require allocations based on service and would preclude allocations based on compensation earned during each year.

The compensation-based allocation might not be unreasonable from an accounting point of view. It might also not be unreasonable from an actuarial point of view within the broader context of pension plans in general (not just in the context of pension plans subject to the minimum funding requirements of ERISA). As a matter of fact, this variation of the unit credit method, although not generally used, is sanctioned for use under the proper circumstances by the American Academy of Actuaries in its 1978 yearbook containing recommendations regarding acceptable actuarial principles and practices in connection with pension plans. However, the legislative mandate of section 3(31) and the general purposes of ERISA would not be satisfied by the mere reliance of the Secretary on judgments made by others for different purposes or in broader contexts.

Compensation-based allocations would significantly defer the funding of normal costs for final average pay plans using the unit credit method. (Normal cost with respect to each participant would rise each year not only as a result of the increasing age of, but also as a result of the increasing compensation paid to, each participant.) A unit credit method with an allocation based only on years of service also results in a rising amount of normal cost viewed as a percentage of compensation. However, the rate of increase of normal cost as a percentage of compensation is substantially less than the rate of increase experienced under a method also based on compensation. The adverse consequences of deferring the funding of normal costs are made even more severe when there are experience losses, or when actuarial assumptions must be modified and added liabilities recovered through additional contributions.

Consideration was given to proscribing this method only when its use becomes unacceptable in a particular set of facts and circumstances. However, such a provision would nonetheless require a change in funding method at the time such circumstances arise that would result in dramatic contribution increases at the time of the change. Such sharp increases in required contributions would not, as a practical matter, enhance the financial stability of the plan. Therefore, the regulations would provide an absolute, rather than a limited, prohibition of this particular variation of the unit credit funding method.

One provision of paragraph (d) prohibits the anticipation of certain benefit changes. Another provision prohibits anticipating the plan affiliation of future participants. The future affiliation provision applies most commonly to projected benefit methods.

The regulation also requires the inclusion of all liabilities under the plan and prohibits the production, by design, of experience gains and losses. Finally, the regulation contains rules relating to the treatment of pre-retirement ancillary benefit costs.

Transitional Rules

A change in funding method to conform to the regulation would not be required before final regulations are published. However, some of the required changes would result in substantial increases in plan costs. For example, a change from the unit credit variation using a compensation-based allocation with a final average pay plan would result in significantly greater contributions under the plan. Therefore, comments are particularly requested on how to ease the burden of change from such methods, if proscribed by final regulations, to methods that would require significantly greater contributions.

Comments and Requests for a Public Hearing

Before adopting these proposed regulations, consideration will be given to any written comments that are submitted (preferably eight copies) to the Commissioner of Internal Revenue. All comments are available for public inspection and copying. A public hearing will be held upon written request to the Commisssioner by any person who has submitted written comments. However, it is anticipated that any public hearing will be deferred until the issuance of further proposed regulations regarding section 412. If a public hearing is held, notice of the time and place will be published in the **Federal Register.**

Drafting Information

The principal author of these proposed regulations was Thomas F. Rogan of the Employee Plans and Exempt Organizations Division of the Office of Chief Counsel, Internal Revenue Service. However, personnel from other offices of the Internal Revenue Service and Treasury Department participated in developing the regulations, both on matters of substance and style.

Proposed amendments to the regulations

The Income Tax Regulations, 26 CFR Part 1, are amended by adding in the appropriate place the following new section:

§ 1.412(c)(3)-1 Reasonable funding methods.

(a) *Introduction*—(1) *In general.* This section prescribes rules for determining whether or not, in the case of an on-going plan, a funding method is reasonable for purposes of section 412(c)(3). A method is unreasonable only if it is found to be inconsistent with a rule prescribed in this section. The term "reasonable funding method" under this section has the same meaning as the term "acceptable actuarial cost method" under section 3(31) of the Employee Retirement Income Security Act of 1974 (ERISA).

(2) *Computations included in method.* The funding method of a plan includes not only the overall funding method used by the plan, but also each specific method of computation used in applying the overall method. However, the choice of which actuarial assumptions are appropriate is not a part of the funding method. For example, the decision to use or not to use a mortality factor in the funding method. Similarly, the specific mortality rate determined to be applicable to a particular plan year is not part of the funding method. See section 412(c)(5), requiring prior approval to change the funding method used by a plan.

(3) *Plans using shortfall.* The shortfall method described in § 1.412(c)(1)-2 is a specific method of computation used in applying the overall funding method for certain collectively bargained plans. Therefore, under paragraph (a)(2) of this section, the shortfall method is a funding method. The funding method of a plan that uses the shortfall computation method must be a reasonable funding method under this section. The use of the shortfall method also must be reasonable. Paragraphs (b) and (c) of this section, relating to cost under a reasonable funding method, apply in the short-fall method to the anticipated annual charge under § 1.412(c)(1)-2(d)(1)

(4) *Scope of funding method.* Except for the shortfall method, a reasonable funding method is applied only to the computation of—

(i) The normal cost of a plan for a plan year; and, if applicable,

(ii) The bases established under section 412(b)(2) (B), (C), and (D), and (3)(B) ("amortizable bases").

(b) *Basic funding formula under reasonable funding method*—(1) *Formula.* At any time, the present value of future benefits under a reasonable funding method must equal the sum of the following amounts:

(i) The present value of normal costs over the future working lifetime of participants;

(ii) The sum of the unamortized portions of amortizable bases, if any, treating credit bases under section 412(b)(3)(B) as negative numbers; and

(iii) The plan assets, decreased by a credit balance (and increased by a debit balance) in the funding standard account under section 412(b).

(2) *Example.* The principles of paragraph (b)(1) of this section are illustrated by the following example:

Example. Assume that a plan, using funding method A, is in its first year. No contributions have been made to the plan, other than a nominal contribution to establish a corpus for the plan's trust. There is no past service liability, and the normal cost is a constant percentage of an annually determined amount. The constant percentage is 99 percent, and the annually determined amount is the excess of the present value of future benefits over plan assets. The present value of future benefits is $10,000. Under paragraph (b)(1) of this section, the present value of future benefits must equal the present value of future normal costs plus plan assets. (No amortizable bases exist, nor are there credit or debit balances.) Under method A, the present value of future normal costs would equal the sum of a series of annually decreasing amounts. Because of the constant percentage factor, the present value of future normal costs over the years can never equal $10,000, the present value of future benefits. In effect, then, assets under method A can never equal the present value of future benefits if all assumptions are exactly realized. Therefore, method A is not a reasonable actuarial method.

(c) *Normal cost under reasonable funding method*—(1) *General rule.* Normal cost under a reasonable funding method must be expressed as—

(i) A level dollar amount; or a level percentage of pay, computed on either an individual basis or an aggregate basis; or

(ii) An amount equal to the present value of benefits accruing for a particular plan year.

(2) *Application to shortfall.* Paragraph (c)(1) will not fail to be satisfied merely because an amount described in (i) or (ii) is expressed as permitted under the shortfall method.

(3) *Use of salary scale*—(i) *General acceptability.* The use of a salary scale assumption is not inappropriate merely because of the funding method with which it is used. Therefore, in determining whether actuarial assumptions are reasonable, a salary scale will not be considered to be prohibited merely because a particular funding method is being used.

(ii) *Projection to appropriate salary.* Under a reasonable funding method, salary scales reflected in projected benefits must project salaries to the salary on which benefits would be based under the plan at the age when the receipt of benefits is expected to begin.

(4) *Allocation of liabilities.* This subparagraph (4) applies to plans determining normal cost under paragraph (c)(1)(ii) of this section. In determining a plan's normal cost and accrued liability for a particular plan year, the projected benefits of the plan must be allocated between past years and future years. Except in the case of a career average pay plan, this allocation must be in proportion to the applicable rates of benefit accrual under the plan. Thus, the allocation to past years would be effected by multiplying the projected benefit by a fraction. The numerator of the fraction would be the participant's credited years of service. The denominator would be the participant's anticipated total credited years of service at normal retirement age. Adjustments would be made to account for changes in the rate of benefit accrual. An allocation based on compensation would not be permitted. In the case of a career average pay plan, an allocation between past and future service benefits must be reasonable.

(5) *Example.* The principles of paragraph (c) of this section are illustrated by the following example:

Example. Assume that a plan, using funding method B, bases benefits on final average pay. Under method B, the past service liability on any date equals the present value of the accrued benefit on that date based on compensation as of that date. The normal cost for any year equals the present value of a certain amount. That amount is the excess of the projected accrued benefit at the end of the year over the actual accrued benefit at the beginning of the year. Accrued benefits, projected as of the end of a year, reflect a one-year salary projection. Under paragraph (c)(3)(ii) of this section, salary scales reflected in projected benefits must project salaries to the salary on which benefits would be based under the plan at the age when the receipt of benefits under the plan is expected to begin. Because the plan is not a career average pay plan and compensation is projected only one year, method B is not a reasonable funding method. (Under paragraph (c)(3)(i) of this section, the use of a salary scale assumption could be required with a unit credit method if, without the use of a salary scale, assumptions in the aggregate are unreasonable.)

(d) *Prohibited considerations under a reasonable funding method*—(1) *Anticipated benefit changes.* A reasonable funding method does not anticipate changes in plan benefits—

(i) That become effective, whether or not retroactively, in a future plan year; or

(ii) Except as provided by the Commissioner, that become effective after the first day of, but during, a current plan year.

(2) *Anticipated future participants*—(i) *In general.* A reasonable funding method must not anticipate the affiliation with the plan of future participants. Thus, under a reasonable funding method, the plan population is limited to, and must include, three classes of individuals: Participants currently employed in the service of the employer; former participants who either terminated service with the employer, or retired, under the plan; and all other individuals currently entitled to benefits under the plan.

(ii) *Special exclusion for "rule of parity" cases.* Under a reasonable funding method, certain individuals may be excluded from the second class of individuals described in paragraph (d)(2)(i) of this section. The excludable individuals are those former participants who have terminated service with the employer without vested benefits and whose service might be taken into account in future years because the "rule of parity" of section 411(a)(6)(D) does not permit that service to be disregarded. However, if the plan's experience as to separated employees' returning to service has been such that the exclusion described in this subparagraph would be unreasonable, the exclusion would no longer apply.

(e) *Miscellaneous requirements*—(1) *Inclusion of all liabilities.* Under a reasonable funding method, all liabilities of the plan for benefits, whether vested or not, must be taken into account.

(2) *Treatment of allocable items.* Under a reasonable funding method that allocates assets to individual participants to determine costs, the allocation of assets among participants, or of liabilities among different elements of past or future service, must be reasonable. An initial allocation of assets among participants will be considered reasonable only if it is in proportion to related liabilities. However, it may be unreasonable to continue to allocate assets on this basis beyond the initial year.

(3) *Production of experience gains and losses.* If each actuarial assumption is exactly realized under a reasonable funding method, no experience gains or losses are produced.

(4) *Examples.* The principles of paragraph (e) of this section are illustrated by the following examples:

Example 1. Assume that a plan, using funding method C, determines normal cost by computing the present value of benefits expected to be accrued under the plan by the end of 10 years after the valuation date and adding to this the present value of benefits expected to be paid within these 10 years. Plan assets are subtracted from the sum of the two present value amounts. The difference then is divided by the present value of salaries projected over the 10 years. Under paragraph (e)(1) of this section, all liabilities of a plan must be taken into account. Because method C takes into account only benefits paid or accrued by the end of 10 years, it is not a reasonable funding method.

Example 2. Assume that a plan that has 2 participants and that previously used the unit credit cost method wishes to change the funding method at the beginning of the plan year to funding method D, a modification of the aggregate cost method. The modification consists in determining normal cost for each of the 2 participants under the plan. Therefore, it requires an allocation of assets to each participant for valuation purposes. The actuary proposes to allocate the assets on hand at the beginning of the plan year of the change in funding method in proportion to the accrued liabilities calculated under the unit credit cost method. The relevant results of the calculations are shown below:

	Employees		
	M	N	Totals
Accrued liabilities (unit credit method):			
$ amount	15,670	906	16,576
% of total	94.53	5.47	100.00
Assets:			
$ amount	7,835	453	8,288
% of total	94.53	5.47	100.00

The proposed allocation in proportion to the accrued liabilities under the unit credit cost method satisfies the requirements of paragraph (e)(2) of this section at the beginning of the first plan year for which the new method is used.

Example 3. The facts are the same as in example 2. However, the actuary proposes to allocate all the assets to employee M, the older employee. Method D, under these facts, is not an acceptable funding method because the allocation is not in proportion of related liabilities as required under paragraph (e)(2) of this section.

Example 4. Assume that a plan, using funding method E, determines normal cost as a constant percentage of compensation. (This percentage is determined as follows: The excess of projected benefits over accrued benefits is computed. Then the present value of this excess is divided by the present value of future salaries.) However, the accrued liability is computed each year as the present value of accrued benefits. (This computation does not reflect normal cost as a constant percentage of compensation. Thus, normal cost under the plan does not link accrued liabilities under the plan for consecutive years as would be the case, for example, under a unit credit cost method.) In determining gains and losses, method E compares the actual unfunded liability (the accrued liability less assets) with the expected unfunded liability (the sum of the actual unfunded liability in the previous year and the normal cost for the previous year less the contribution made for the previous year, all adjusted for interest). Under paragraph (e)(3) of this section, if actuarial assumption are exactly realized, experience gains and losses must not be produced. Under method E, the use of a constant percentage in computing normal cost (and the expected unfunded liability) coupled with the manner of computing the accrued liability (and the actual unfunded liability) generally produces gains in the earlier years and losses in the later years if each actuarial assumption is exactly realized. Therefore, method E is not a reasonable funding method.

(f) *Treatment of pre-retirement ancillary benefit costs*—(1) *General rule.* Under a reasonable funding method, pre-retirement ancillary benefit costs must be computed by using the same method used to compute retirement benefit costs (other than the cost of benefits to which section 401(h) applies) under a plan.

(2) *Exception for certain insurance contracts.* Under a reasonable funding method, regardless of the method used to compute retirement benefit costs, the cost of a pre-retirement ancillary benefit may equal the premium paid for that benefit under an insurance contract if—

(i) The pre-retirement ancillary benefit is provided under the contract, and

(ii) The benefit is guaranteed under the contract.

(3) *Exception for one-year term funding.* Under a reasonable actuarial method, regardless of the method used to compute retirement benefit costs, the cost of a pre-retirement ancillary benefit may be computed on a one-year term basis if—

(i) The cost of pre-retirement ancillary benefits computed on a one-year term basis is not significant in relationship to total plan cost; or

(ii) The cost of pre-retirement ancillary benefits, computed on a one-year basis, does not differ significantly from the cost of pre-retirement ancillary benefits, computed under the method for computing retirement benefits.

(4) *Meaning of "significant"*—(1) *Significant relationship safe harbor.* Under paragraph (f)(3)(i) of this section, the relationship of costs is not significant if the term cost of pre-retirement ancillary benefits is less than 5 percent of the total plan costs.

(ii) *Significant difference safe harbor.* Under paragraph (f)(3)(ii) of this section, pre-retirement ancillary benefit costs do not differ significantly if costs determined under one-year term funding exceed 90 percent of such costs determined under the method for funding retirement benefits.

(5) *Treatment of vesting.* For purposes of this paragraph, vesting is not a pre-retirement ancillary benefit. Thus, the cost of vesting may not be included in computing pre-retirement ancillary benefit costs.

(g) *Effective date and transition rule.* Paragraphs (a) through (f) of this section apply to any valuation of a plan's liability (within the meaning of section 412 (c)(9)) made after [insert date 60 days after publication of this section in the Federal Register as a Treasury decision]. The reasonableness of a funding method used in making such a valuation before [insert date 61 days after such publication] will be determined on the basis of such published guidance as was available on the date the valuation was made.

Jerome Kurtz,

Commissioner of Internal Revenue.

[FR Doc. 79-30564 Filed 9-28-79; 12:55 pm]

BILLING CODE 4830-01-M

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26 CFR Part 1

Income Tax; Taxable Years Beginning After December 31, 1953; Requirements Relating to Certain Exchanges Involving a Foreign Corporation

AGENCY: Internal Revenue Service, Treasury.

ACTION: Proposed rulemaking cross-reference to temporary regulations.

SUMMARY: In the Rules and Regulations portion of this Federal Register, the Internal Revenue Service is issuing temporary income tax regulations concerning requirements relating to certain exchanges involving a foreign corporation. The temporary regulations also serve as a notice of proposed rulemaking for final income tax regulations.

DATES: The temporary regulations apply to exchanges beginning after December 31, 1977. The proposed regulations are to be effective for the same period. The regulations are prescribed under section 367 (b) of the Internal Revenue Code as amended by section 1042(a) of the Tax Reform Act of 1976.

Written comments and requests for a public hearing must be delivered or mailed on or before December 4, 1979.

ADDRESS: Send comments and requests for a public hearing to: Commissioner of Internal Revenue Service, Attention: CC:LR:T (LR-2-78), Washington, D.C. 20224.

FOR FURTHER INFORMATION CONTACT: Daniel Horowitz of the Legislation and Regulations Division, Office of the Chief Counsel, Internal Revenue Service, 1111 Constitution Avenue, N.W., Washington, D.C. 20224. Attention: CC:LR:T (LR-2-78), 202-566-3289.

SUPPLEMENTARY INFORMATION: The temporary regulations in the Rules and Regulations portion of this issue of the Federal Register amend 26 CFR Part 7. The final regulations which are proposed to be based on the temporary regulations would amend 26 CFR Part 1.

For the text of the temporary regulations, see FR Doc. 79-30828 [T.D. 7646] published in the Rules and Regulations portion of this issue of the Federal Register.

BILLING CODE 4830-01-M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[FRL 1333-6]

Approval and Promulgation of State Implementation Plans; Nonattainment Area Plan for Colorado

AGENCY: Environmental Protection Agency.

ACTION: Proposed Rulemaking.

SUMMARY: Elsewhere in today's Federal Register EPA is conditionally approving the Colorado plan where there are deficiencies and the State provides assurances that it will submit corrections. This notice solicits comments on deadlines for conditionally approved items and on the adequacy of transportation control measures schedules recently submitted to EPA by the State. Conditional approvals mean that Section 176 and Section 316 of the Clean Air Act, and new source growth sanctions will not apply unless the State fails to submit the necessary SIP revisions by the scheduled dates, or.

unless the revisions are not approved by EPA. Procedures for application of these sanctions are discussed elsewhere in the **Federal Register.**

DATES: Comments must be received on or before November 5, 1979.

ADDRESSES: Comments should be directed to: Robert R. DeSpain, Chief, Air Programs Branch, Region VIII, Environmental Protection Agency, 1860 Lincoln Street Denver, Colorado 80295 (303) 837-3471.

Copies of the materials submitted by the Governor and comments received on this proposal, may be examined during normal business hours at:

Environmental Protection Agency, Region VIII Library, 1860 Lincoln Street, Denver, Colorado 80295.

Environmental Protection Agency, Public Information Reference Unit, Room 2922, 401 M Street, S.W., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Robert R. DeSpain, Chief, Air Programs Branch, Region VIII, 1860 Lincoln Street, Denver, Colorado 80295 (303) 837-3471.

SUPPLEMENTARY INFORMATION:

Conditional Approval Time Schedules

The deficiencies discussed elsewhere in today's **Federal Register** and the time schedules in which the State must correct them are:

1. Inspection/Maintenance (I/M)—The State of Colorado must adopt an adequate I/M program by March 1, 1980. In the interim they must meet the following schedules:

January 1, 1980—Study completed, submitted to Governor
January 12, 1980—I/M included on list of Governor's Call items for the 1980 legislative sessions
February 1, 1980—Study results reported to legislature
Fedbruary 1, 1980—Bill introduced in legislature—copy to EPA
March 1, 1980—Submission to EPA legislation signed into law by the Governor, as well as schedules (milestones, dates, responsible agency) to implement the I/M program and corrections to other noted deficiencies

2. Regulation 7, Volatile Organic Compounds—The Commission will change this regulation so that it requires reasonable available control technology for existing Group I sources by March 1, 1980. In the interim, they must meet the following schedules:

November 1, 1979—Notice of public hearing
January 3, 1980—Public hearing and draft regulations submitted to EPA
March 1, 1980—Adopt new regulation and submit to EPA

3. Regulation 3, New Source Review Program—The Commission will change this regulation so it is consistent with Section 173 of the Clean Air Act by March 1, 1980.

4. Pueblo Attainment Demonstration—By January 1, 1980, the State must submit to EPA an air quality modelling demonstration showing that the emissions from the Colorado Fuel and Iron steel mill do not violate the 24-hour total suspended particulate standard.

5. section 172(b)(11)(A) of the Clean Air Act—By March 1, 1980, a program requiring this analysis of alternative sites, sizes, environmental controls, etc., must be adopted by the State.

(Proposal)

Denver and Larimer-Weld Transportation Control Measures Schedules

On July 5, 1979, and July 27, 1979, the State of Colorado submitted transportation control measures schedules for Larimer-Weld and Denver, respectively. As explained elsewhere in today's **Federal Register,** both the Denver (CO and ozone) and Larimer-Weld (CO) plans included transportation control measures and commitments to implement them but lacked the detailed schedules for implementation and study of the measures identified in Section 108(f) of the Act. EPA has reviewed the supplemental submittals and proposes to conditionally approve the schedules.

In addition to the Larimer-Weld Transportation control measures schedules, the July 5, 1979, submittal contained a memorandum from the State to the Director of the Larimer-Weld Regional Council of Governments (LWRCOG) describing the need for LWRCOG to revise their schedules. EPA agrees that, to be unconditionally approved, the schedules must be revised to describe the specific actions needed to implement a control measure, including key interim dates.

EPA has received a commitment from the State (letter dated August 15, 1979) that Greeley and Fort Collins, together with LWRCOG will revise the schedules and the State will submit them to EPA by January 1, 1980. Based upon this assurance, EPA proposes to conditionally approve the Larimer-Weld schedules provided that adequate schedules are submitted to EPA no later than January 1, 1980.

The Governor's July 27, 1979, supplemental submittal included the Denver transportation control measures schedules. EPA has reviewed the schedules and identified several minor deficiencies. Therefore, EPA proposes to conditionally approve the Denver transportation control measures provided that the following additional information is submitted to EPA by January 1, 1980.

1. Milestones for obtaining funds, possible funding sources, and target amounts associated with each measure.

2. Additional description of the HOV lane study, the parking management plan, and the vanpool demonstration program to demonstrate that such activities reflect progress over that already achieved.

Under Executive Order 12044, EPA is required to judge whether a regulation is "significant" and therefore subject to the procedural requirements of the Order or whether it may follow other specialized development procedures. EPA labels these other regulations "specialized." I have reviewed this regulation and determined that it is a specialized regulation not subject to the procedural requirements of Executive Order 12044.

This notice of proposed rulemaking is issued under authority of Section 110 of the Clean Air Act as amended.

Dated: September 14, 1979.

Roger L. Williams,
Regional Administrator.

[FR Doc. 79-31032 Filed 10-4-79; 8:45 am]
BILLING CODE 6560-01-M

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40 CFR Part 120

[FRL 1333-5]

Water Quality Standards, Surface Waters of the State of Ohio

AGENCY: Environmental Protection Agency.

ACTION: Extension of Public Comment Period.

SUMMARY: On August 9, 1978, the Regional Administrator for Region V of the United States Environmental Protection Agency (EPA), approved the water quality standards adopted by the State of Ohio except for several provisions. On July 6, 1979, the Agency proposed rules to correct the deficiencies in the non-approved portions. The EPA held three public hearings in the State of Ohio, to receive comments on the Proposed Rulemaking for Ohio Water Quality Standards. The hearings were announced in the **Federal Register,** Volume 44, Number 151, on August 3, 1979. The public hearings took place during the afternoon and evening on September 17, 1979, in Columbus, September 19, 1979, in Dayton, and September 21, 1979, in Akron. The final date for receipt of written comments was on or before October 5, 1979. Because of a need to allow additional preparation time, for all parties, the final date for receipt of written comments is hereby extended to the close of business on October 19, 1979.

DATES: All comments received by the close of business on October 19, 1979, will be considered in the preparation of any final rulemaking.

ADDRESSES: Comments should be submitted to the person listed immediately below.

FOR FURTHER INFORMATION CONTACT: William Benjey, Water Division, EPA, Region V, 230 South Dearborn Street, Chicago, Illinois 60604, (312-353-2172.)

SUPPLEMENTARY INFORMATION: The EPA held three public hearings in the State of Ohio, to receive comments on a Proposed Rulemaking for Ohio Water Quality Standards.

The substantive provisions of the Proposed Rulemaking would increase the stringency of the dissolved oxygen and cyanide criteria for warmwater habitat protection, provide for consistent methodologies in determining thermal and non-thermal mixing zones, set the definitions of low-flow streams at 0.1 cubic foot per second for the flow which occurs over 7 days each 10 years, and would require the State to evaluate more thoroughly, justification submitted to EPA for beneficial use downgradings, of stream segments.

A copy of the full text of the Proposed Rulemaking has been sent to the main public library in each county in Ohio and is available for review there. The same document may also be obtained by writing, calling or visiting:

William Benjey, Water Division, EPA, 230 South Dearborn, Chicago, Illinois 60604 (312) 353-2172.

This document is available at no cost to the public.

Dated: October 2, 1979.

John McGuire,

Regional Administrator, Region V, United States Environmental Protection Agency.

[FR Doc. 79-31077 Filed 10-4-79; 8:45 am]

BILLING CODE 6560-01-M

40 CFR Part 162

[OPP-30029A; FRL 1334-7]

Pesticide Use Restrictions; Extension of Comment Period

AGENCY: Environmental Protection Agency (EPA), Office of Pesticide Programs.

ACTION: Extension of Comment Period for a proposed rule.

SUMMARY: This notice extends the comment period for the proposed rule amending 40 CFR 162.31 by adding uses of active ingredients which the EPA proposes to classify for restricted use. The request to extend the comment period was submitted by some registrants of pesticide products and Federal Agencies. This extension will provide additional time for assembling information on the proposal.

DATE: Comments must be received by October 31, 1979.

ADDRESS: Send comments to Document Control Officer, Office of Toxic Substances, Chemical Information Division (TS-793), Room 447, EPA, 401 M Street, S.W., Washington, D.C. 20460. Comments should be filed in triplicate if possible and bear the identifying notation "OPP-30029". All written comments will be available for public inspection from 8:30 a.m. to 4 p.m., Monday through Friday.

FOR FURTHER INFORMATION CONTACT: Mr. Walter Waldrop (TS-770), Office of Pesticide Programs, EPA, 499 South Capitol Street, S.W., Marfair Building, 3rd floor, Washington, D.C. 20460 (202/472-9403).

SUPPLEMENTARY INFORMATION: By Federal Register Notice dated August 1, 1979 (44 FR 45218) and subsequently corrected August 7, 1979 (44 FR 46303), the Administrator issued a proposed rule classifying certain uses of 21 active ingredients for restricted use. A 60-day comment period expiring October 1, 1979, was allowed for filing written responses. At the request of several interested parties, including registrants affected by the proposed rule and Federal agencies, the deadline for filing such written responses is hereby extended to October 31, 1979.

Dated: September 28, 1979.

Edwin L. Johnson,

Deputy Assistant Administrator for Pesticide Programs.

[FR Doc. 79-31016 Filed 10-4-79; 8:45 am]

BILLING CODE 6560-01-M

FEDERAL EMERGENCY MANAGEMENT AGENCY

44 CFR Part 67

[Docket No. FEMA-5706]

National Flood Insurance Program; Proposed Flood Elevation Determinations

AGENCY: Federal Insurance Administration, FIA.

ACTION: Proposed Rule.

SUMMARY: Technical information or comments are solicited on the proposed base (100-year) flood elevations listed below for selected locations in the nation. These base (100-year) flood elevations are the basis for the flood plain management measures that the community is required to either adopt or show evidence of being already in effect in order to qualify or remain qualified for participation in the National Flood Insurance Program (NFIP).

DATES: The period for comment will be ninety (90) days following the second publication of this proposed rule in a newspaper of local circulation in each community.

ADDRESSES: See table below.

FOR FURTHER INFORMATION CONTACT: Mr. R. Gregg Chappell, National Flood Insurance Program, (202) 426-1460 or Toll Free Line (800) 424-8872 (in Alaska and Hawaii call Toll Free Line (800) 424-9080), Room 5148, 451 7th Street S.W., Washington, D.C. 20410.

SUPPLEMENTARY INFORMATION: The Federal Insurance Administrator gives notice of the proposed determinations of base (100-year) flood elevations for selected locations in the nation, in accordance with section 110 of the Flood Disaster Protection Act of 1973 (Pub. L. 93-234), 87 Stat. 980, which added section 1363 to the National Flood Insurance Act of 1968 (Title XIII of the Housing and Urban Development Act of 1968 (Pub. L. 90-448), 42 U.S.C. 4001-4128, and 44 CFR 67.4 (a)).

These elevations, together with the flood plain management measures required by § 60.3 of the program regulations, are the minimum that are required. They should not be construed to mean the community must change any existing ordinances that are more stringent in their flood plain management requirements. The community may at any time enact stricter requirements on its own, or pursuant to policies established by other Federal, State, or Regional entities. These proposed elevations will also be used to calculate the appropriate flood insurance premium rates for new buildings and their contents and for the second layer or insurance on existing buildings and their contents.

The proposed base (100-year) flood elevations for selected locations are:

Proposed Base (100-Year) Flood Elevations

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
South Dakota	Fort Pierre (City), Stanley County	Bad River	U.S. Highway 83—50 feet upstream from centerline	*1,435
			(First crossing)—Chicago and North Western Railroad—50 feet upstream from centerline.	*1,437
			(Second crossing)—Chicago and North Western Railway—50 feet downstream from centerline.	*1,445
			Upstream limit of flooding affecting City of Fort Pierre	*1,448
		Bad River Overflow	U.S. Highway 83—20 feet upstream from centerline	*1,435
			Park Street—50 feet upstream from centerline	*1,439
		Missouri River	Downstream limit of flooding affecting City of Fort Pierre	*1,428
			Upstream limit of flooding affecting City of Fort Pierre	*1,429

Maps available at: Planning Commission, City Hall, Fort Pierre, South Dakota.

Send comments to: Honorable J. Tipps Hamilton, Mayor, City of Fort Pierre, P.O. Box 637, Fort Pierre, South Dakota 57532.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Tennessee	Johnson (City), Washington County.	Brush Creek	Most downstream Corporate Limits—at centerline	*1,546
			Smith Street—at centerline	*1,564
			Southern Railway Spur upstream from Smith Street—50 feet downstream from centerline.	*1,565
			Southern Railway Spur upstream from Smith Street—50 feet upstream from centerline.	*1,570
			Broadway—at centerline	*1,593
			New Street—at centerline	*1,602
			End of Covered Channel upstream from Elm Street—450 feet downstream from centerline.	*1,613
			Start of Covered Channel	*1,631
			Southern Railway—at centerline	*1,636
			Lyle Street—at centerline	*1,660
			300 feet upstream from confluence with Tributary No. 1 to Brush Street.	*1,666
			Private Road downstream from Clinchfield Railroad—5 feet downstream from centerline.	1,675
			150 feet upstream from centerline of Private Road—at Corporate Limits.	*1,689
			Area from 500 feet downstream from South Roan Street to 900 feet upstream from Buffalo Street.	*#2
		King Creek	West King Street—start of Covered Channel—at centerline	*1,624
			West Watauga Street—at centerline	*1,625
			Belmont Street—25 feet downstream from centerline	*1,630
			Hillcrest Drive—at centerline	*1,640
			Patoclas Road—250 feet upstream from centerline	*1,645
			West Market Street—at centerline	*1,650
			Lincoln Avenue—at centerline	*1,673
			Area from West King Street to 500 feet downstream from West Watauga Street.	*#2
		Knob Creek	Corporate Limits closest to mouth—at centerline	*1,458
			Andrew Johnson Highway—500 feet downstream from centerline	*1,472
			Andrew Johnson Highway—150 feet upstream from centerline	*1,475
			North Roan Street—50 feet upstream from centerline	*1,478
			420 feet downstream from centerline of Freeway Exit Ramp downstream from State Route 37.	*1,495
			Upstream end of Covered Channel	*1,505
			Most upstream Corporate Limits—75 feet downstream from centerline	*1,530
		Sinking Creek	Most downstream Corporate Limits	*1,550
			Orlando Drive—at centerline	*1,592
			State Highway 67—at centerline	*1,621
			State Route 37—50 feet upstream from centerline	*1,638
			Lafe Cox Road—300 feet upstream from centerline	*1,660
			Buffalo Road—5 feet upstream from centerline	*1,681
			Downstream end of Clinchfield Railroad Culvert	*1,721
			Hickory Springs Road—150 feet upstream from centerline	*1,752
			Log Bridge—at centerline	*1,791
			Limit of flooding affecting Johnson City	*1,794

Maps available at: City Hall, Johnson City, Tennessee.

Send comments to: Honorable John G. Love, Mayor, City of Johnson City, P.O. Box 2150, Johnson City, Tennessee 37601.

(National Flood Insurance Act of 1968 (Title XIII of Housing and Urban Development Act of 1968), effective January 28, 1969 (33 FR 17804, November 28, 1968), as amended (42 U.S.C. 4001–4128); Executive Order 12127, 44 FR 19867; and delegation of authority to Federal Insurance Administrator 44 FR 20963.)

Issued: September 21, 1979.

Gloria M. Jiminez,

Federal Insurance Administrator.

[FR Doc. 79-30815 Filed 10-4-79; 8:45 am]

BILLING CODE 6718-03-M

44 CFR Part 67

[Docket No. FEMA 5705]

National Flood Insurance Program; Proposed Flood Elevation Determinations

AGENCY: Federal Insurance Administration, FIA.

ACTION: Proposed Rule.

SUMMARY: Technical information or comments are solicited on the proposed base (100-year) flood elevations listed below for selected locations in the nation. These base (100-year) flood elevations are the basis for the flood plain management measures that the community is required to either adopt or show evidence of being already in effect in order to qualify or remain qualified for participation in the National Flood Insurance Program (NFIP).

DATES: The period for comment will be ninety (90) days following the second publication of this proposed rule in a newspaper of local circulation in each community.

ADDRESSES: See table below.

FOR FURTHER INFORMATION CONTACT: Mr. R. Gregg Chappell, National Flood Insurance Program, (202) 426–1460 or Toll Free Line (800) 424–8872 (in Alaska and Hawaii call Toll Free Line (800) 424–9080), Room 5148, 451 7th Street SW., Washington, D.C. 20410.

SUPPLEMENTARY INFORMATION: The Federal Insurance Administrator gives notice of the proposed determinations of base (100-year) flood elevations for selected locations in the nation, in accordance with section 110 of the Flood Disaster Protection Act of 1973 (Pub. L. 93–234), 87 Stat. 980, which added section 1363 to the National Flood Insurance Act of 1968 (Title XIII of the Housing and Urban Development Act of 1968 (Pub. L. 90–448), 42 U.S.C. 4001–4128, and 44 CFR 67.4(a).

These elevations, together with the flood plain management measures required by Section 60.3 of the program regulations, are the minimum that are required. They should not be construed to mean the community must change any existing ordinances that are more stringent in their flood plain management requirements. The community may at any time enact stricter requirements on its own, or pursuant to policies established by other Federal, State, or Regional entities. These proposed elevations will also be used to calculate the appropriate flood insurance premium rates for new buildings and their contents and for the second layer of insurance on existing buildings and their contents.

The proposed base (100-year) flood elevations for selected locations are:

Proposed Base (100-Year) Flood Elevations

State	City/town/county	Source of flooding	Location	*Elevation, meters above mean sea level
Commonwealth of Puerto Rico	Rio Guayanilla Basin	Rio Guayanilla	At Mouth	*1.8
			Highway 127 (most downstream crossing)—at centerline	*10.0
			Higway 127 (second crossing)—at centerline	*13.0
			Highway 2—35 meters upstream from centerline	*24.0
		Rio Macana	At Mouth	*1.8
			Highway 127—40 meters upstream from centerline	*3.5
			Highway 2—20 meters upstream from centerline	*9.0

Maps available at: Puerto Rico Planning Board, Minillas Government Center, North Building, 14th Floor, Santurce, Puerto Rico.

Send comments to: Mr. Boris L. Oxman, Coordinator for National Flood Insurance Program, Puerto Rico Planning Board, Minillas Government Center, 14th Floor, Box 41119, Santurce, Puerto Rico 00940.

State	City/town/county	Source of flooding	Location	*Elevation, meters above mean sea level
Commonwealth of Puerto Rico	Pueblo of Orocovis	Rio Orocovis	Puerto Rico Highway 155 (First Bridge)—at centerline	*487.2
			Confluence with Quebrada Los Saltos	*497.7
			Puerto Rico Highway 155 (Second Bridge)—at centerline	*499.8

Maps available at: Puerto Rico Planning Board, Minillas Government Center, North Building, 14th Floor, Santurce, Puerto Rico.

Send comments to: Mr. Boris L. Oxman, Coordinator for National Flood Insurance Program, Puerto Rico Planning Board, Minillas Government Center, 14th Floor, Box 41119, Santurce, Puerto Rico 00940.

State	City/town/county	Source of flooding	Location	*Elevation, meters above mean sea level
Commonwealth of Puerto Rico	Rio Cibuco Basin	Rio Cibuco	Puerto Rico Highway 688—100 meters upstream from centerline	*6.0
			Puerto Rico Highway 2—50 meters upstream from centerline	*8.7
			Puerto Rico Highway 676—80 meters upstream from centerline	*10.0
			Puerto Rico Highway 675—50 meters upstream from centerline	*16.6
			2nd Unnamed Road—50 meters upstream from centerline	*20.4
		Rio Indio	Puerto Rico Highway 160—50 meters upstream from centerline	*12.1
		Quebrada Honda	Puerto Rico Highway 2—65 meters upstream from centerline	*21.0
			Calle Calandra—50 meters upstream from centerline	*29.5
			Puerto Rico Highway 2—50 meters downstream from centerline	*42.5
			Puerto Rico Highway 2—50 meters upstream from centerline	*47.2
		Rio De Los Negros	Puerto Rico Highway 159—50 meters upstream from centerline	*77.9
			Puerto Rico Highway 807—10 meters upstream from centerline	*80.0
		Rio Morovis	Weir—20 meters downstream from centerline	*181.5
			Weir—40 meters upstream from centerline	*186.0
			Puerto Rico Highway 617—15 meters upstream from centerline	*189.6

Maps available at: Puerto Rico Planning Board, Minillas Government Center, North Building, 14th Floor, Santurce, Puerto Rico.

Send comments to: Mr. Boris L. Oxman, Coordinator for National Flood Insurance Program, Puerto Rico Planning Board, Minillas Government Center, 14th Floor, Box 41119, Santurce, Puerto Rico 00940.

State	City/town/county	Source of flooding	Location	*Elevation, meters above mean sea level
Commonwealth of Puerto Rico	Lower Arecibo River Basin	Arecibo River	Puerto Rico Highway 2 (1st crossing)—at centerline	*3.8
			Puerto Rico Highway 2 (2nd crossing)—at centerline	*7.8
			Confluence with Tanama River upstream from centerline	*11.6
		Cano Tiburones	Confluence with Atlantic Ocean upstream from centerline	*1.3
		Atlantic Ocean	Coastal Areas	*1.6

Maps available at: Puerto Rico Planning Board, Minillas Government Center, North Building, 14th Floor, Santurce, Puerto Rico.

Send comments to: Mr. Boris L. Oxman, Coordinator for National Flood Insurance Program, Box 41119, Santurce, Puerto Rico 00940.

(National Flood Insurance Act of 1968 (Title XIII of Housing and Urban Development Act of 1968), effective January 28, 1969 (33 FR 17804, November 28, 1968), as amended (42 U.S.C. 4001–4128); Executive Order 12127, 44 FR 19867; and delegation of authority to Federal Insurance Administrator 44 FR 20963.)

Issued: September 13, 1979.

Gloria M. Jimenez,

Federal Insurance Administrator.

[FR Doc. 79–30814 Filed 10–4–79; 8:45 am]

BILLING CODE 6718-03-M

44 CFR Part 67

[Docket No. FI-5550]

Proposed Flood Elevation Determinations for the Town of Buckland, Franklin County, Mass.; Under the National Flood Insurance Program; Correction

AGENCY: Federal Insurance Administration; FEMA.

ACTION: Correction of proposed rule.

SUMMARY: This document corrects a proposed rule on base (100-year) flood elevations that appeared on page 44 FR 34162 of the Federal Register of June 14, 1979.

EFFECTIVE DATE: June 14, 1979.

FOR FURTHER INFORMATION CONTACT: Mr. R. Gregg Chappell, National Flood Insurance Program, (202) 426-1460 or Toll Free Line 800-424-8872, Room 5150, 451 Seventh Street, SW., Washington, D.C. 20410.

The following:

Source of flooding	Location	Elevation in feet, national geodetic vertical datum
Clesson Brook	Just downstream of Ashfield Road (north of confluence of Maynard Brook).	543

Should be corrected to read:

Source of flooding	Location	Elevation in feet, national geodetic vertical datum
Clesson Brook	Just downstream of Ashfield Road (downstream of confluence of Maynard Brook.	543

(National Flood Insurance Act of 1968 (Title XIII of Housing and Urban Development Act of 1968), effective January 28, 1969 (33 FR 17804, November 28, 1968), as amended; 42 U.S.C. 4001-4128; Executive Order 12127, 44 FR 19367; and delegation of authority to Federal Insurance Administrator, 44 FR 20963).

Issued: September 25, 1979.

Gloria M. Jimenez,

Federal Insurance Administrator.

[FR Doc. 79-30813 Filed 10-4-79; 8:45 am]

BILLING CODE 6718-03-M

44 CFR Part 67

[Docket No. FI-5512]

Proposed Flood Elevation Determinations for the City of Athens, Athens County, Ohio; Under the National Flood Insurance Program; Correction

AGENCY: Federal Insurance Administration, FEMA.

ACTION: Correction of proposed rule.

SUMMARY: This document corrects a proposed rule on base (100-year) flood elevations that appeared on page 44 FR 33426 of the Federal Register of June 11, 1979.

EFFECTIVE DATE: June 11, 1979.

FOR FURTHER INFORMATION CONTACT: Mr. R. Gregg Chappell, National Flood Insurance Program, (202) 426-1460 or Toll Free Line 800-424-8872, Room 5150, 451 Seventh Street, SW., Washington, D.C. 20410.

The following:

Source of flooding	Location	Elevation in feet, national geodetic vertical datum
Hocking River	About 790 feet downstream of Whites Mill Dam.	643
Coates Run	At barricaded Bridge (Unnamed Road).	641

Should be corrected to read:

Source of flooding	Location	Elevation in feet, national geodetic vertical datum
Hocking River	About 2900 feet downstream of Whites Mill Dam.	643
Coates Run	At barricaded Bridge (Unnamed Road).	642

(National Flood Insurance Act of 1968 (Title XIII of Housing an Urban Development Act of 1968), effective January 28, 1969 (33 FR 17804, November 28, 1968), as amended; 42 U.S.C. 4001-4128; Executive Order 12127, 44 Fr 19367; and delegation of authority to Federal Insurance Administrator, 44 FR 20963).

Issued: September 25, 1979.

Gloria M. Jimenez,

Federal Insurance Administrator.

[FR Doc. 79-30812 Filed 10-4-79; 8:45 am]

BILLING CODE 6718-03-M

44 CFR Part 67

[Docket No. FEMA 5702]

National Flood Insurance Program; Proposed Flood Elevation Determinations

AGENCY: Federal Insurance Administration, FEMA.

ACTION: Proposed rule.

SUMMARY: Technical information or comments are solicited on the proposed base (100-year) flood elevations listed below for selected locations in the nation. These base (100-year) flood elevations are the basis for the flood plain management measures that the community is required to either adopt or show evidence of being already in effect in order to qualify or remain qualified for participation in the National Flood Insurance Program (NFIP).

DATES: The period for comment will be ninety (90) days following the second publication of this proposed rule in a newspaper of local circulation in each community.

ADDRESSES: See table below.

FOR FURTHER INFORMATION CONTACT: Mr. R. Gregg Chappell, National Flood Insurance Program, (202) 426-1460 or Toll-Free Line (800) 424-8872 (In Alaska and Hawaii call Toll-Free Line (800) 424-9080), Room 5150, 451 7th Street SW., Washington, D.C. 20410.

SUPPLEMENTARY INFORMATION: The Federal Insurance Administrator gives notice of the proposed determinations of base (100-year) flood elevations for selected locations in the nation, in accordance with section 110 of the Flood Disaster Protection Act of 1973 (Pub. L. 93-234), 87 Stat. 980, which added section 1363 to the National Flood Insurance Act of 1968 (Title XIII of the Housing and Urban Development Act of 1968 (Pub. L. 90-448), 42 U.S.C. 4001-4128, and 44 CFR 67.4(a)).

These elevations, together with the flood plain management measures required by § 60.3 of the program regulations, are the minimum that are required. They should not be construed to mean the community must change any existing ordinances that are more stringent in their flood plain management requirements. The community may at any time enact stricter requirements on its own, or pursuant to policies established by other Federal, State, or Regional entities. These proposed elevations will also be used to calculate the appropriate flood insurance premium rates for new buildings and their contents and for the second layer of insurance on existing buildings and their contents.

The proposed base (100-year) flood elevations for selected locations are:

Proposed Base (100-Year) Flood Elevations

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Connecticut	(T) Darien, Fairfield County	Five Mile River	Just upstream of Tokeneke Road	*12
			Just downstream of Conrail	*22
			Just upstream of Conrail	*29
			Approximately 600 feet downstream of Old Kings Highway North	*32
			Just downstream of Old Kings Highway North	*37
			Just upstream of Old Kings Highway North	*42
			Just upstream of Connecticut Turnpike	*46
			At northern corporate limits	*49
		Noroton River	Just upstream of Boston Post Road	*12
			Just upstream of Connecticut Turnpike	*17
			Just downstream of Conrail	*30
			Just upstream of Conrail	*38
			Approximately 2,200 feet upstream of Middlesex Road	*42
			Just upstream of Conrail	*74
			Just downstream of Woodway Road	*90
		Goodwives River	Just upstream of Rings End Road	*12
			Just upstream of Goodwives River Road	*13
			Approximately 1,050 feet upstream of Goodwives River Road	*15
			Approximately 1,100 feet upstream of Goodwives River Road	*19
			Just upstream of Andrews Drive	*33
			Approximately 250 feet downstream of Old Kings Highway South	*37
			Just upstream of Connecticut Turnpike	*44
			Just upstream Old Kings Highway North	*46
			Just upstream of Prospect Avenue	*66
			Just upstream of Granaston Lane	*85
			Approximately 850 feet downstream of Overbrook Lane	*99
			Just upstream of Overbrook Lane	*109
			Just upstream of Buttonwood Lane	*135
		Stony Brook	At confluence with Goodwives River	*12
			Just upstream of Renshaw Road	*16
			Approximately 200 feet downstream of Connecticut Turnpike	*20
			Approximately 350 feet upstream of Connecticut Turnpike	*26
			Approximately 600 feet downstream of Conrail	*60
			Just downstream of Conrail	*66
			Just upstream of Conrail	*71
			Just downstream of West Avenue	*73
			Just upstream of West Avenue	*75
			Approximately 900 feet downstream of Middlesex Road	*92
			Just upstream of Middlesex Road	*95
			Just downstream of High School Lane	*98
			Just downstream of Hanson Road	*110
		Tokeneke Brook	Just upstream of Cross Road	*12
			Just downstream of Dam	*13
			Just upstream of Dam	*25
			Just upstream of Tokeneke Road	*28
			Just upstream of Conrail (first of three crossings)	*32
			Just downstream of Conrail (second of three crossings)	*34
			Just upstream of Conrail (second of three crossings)	*43
			Just downstream of Conrail (third of three crossings)	*44
			Just upstream of Conrail (third of three crossings)	*51
		Long Island Sound	Darien Coastline	*12

Maps available at: Town Office, Public Works Office, Darien, Connecticut.
Send comments to: Mr. William Patrick, First Selectman, Town of Darien, Town Office, Darien, Connecticut 06820.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Connecticut	(t) Mansfield, Tolland County	Williamantic River	Southern Corporate Limit	*250
			At Cider Mill Road	*251
			500 feet upstream from Route 31	*255
			1,000 feet downstream from Central Vermont Railway	*260
			At Coventry Road	*266
			2,000 feet upstream from Northern Central Vermont Railway	*268
			Just downstream of Eagleville Road	*275
			Just upstream from Eagleville Dam	*284
			Just downstream from Plains Road	*287
			Just upstream from Plains Road	*291
			Just downstream from Route 44A	*293
			Just upstream from Route 44A	*296
			Just upstream from Merrow Road	*315
			Approximately 1,400 feet upstream from Merrow Road	*317
			Just upstream from Tolland Road	*325
			At Northern Corporate Limits	*330
		Conantville Brook	At Route 195	*163
			At west bound Interstate 84	*166
			At Conantville Road	*167
			Upstream from Conantville Dam	*196
			At Ash Street	*236
			At upstream dam	*240
			At Pleasant Valley Road	*258
		Natchaug River	1,300 feet from corporate limit	*163
			Just downstream from Williamantic Dam	*168
			Just upstream from Williamantic Dam	*184
		Mount Hope River	At Mansfield Hollow Reservoir	*257
			2,500 feet upstream from Atwoodville Road	*263
			Just upstream from Juniper Lane	*287
			Approximately 2,000 feet downstream from Laurel Lane	*297

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			Just upstream from Laurel Lane	*304
			Just downstream from Mount Hope Road	*310
			2,300 feet upstream from Mount Hope Road	*333
			At the upstream corporate limit	*340

Maps available at: Town Clerk's Office, Town Hall, Mansfield, Connecticut 06286.

Send comments to: Mr. Martin H. Berliner, Town Manager, Town of Mansfield, Town Hall, 4 South Eagleville Road, Mansfield, Connecticut 06286.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Connecticut	(t) North Haven, New Haven County.	Quinnipiac River	Downstream corporate limit	*11
			Upstream side of Broadway	*11
			Upstram side of State Route 22	*12
			2.0 Miles downstream of Toelles Road	*15
			0.6 Miles downstream of Toelles Road	*20
			Upstream corporate limit	*23
		Muddy River	Mouth of Quinnipiac River	*11
			1,500 feet u/s of Interstate 91	*13
			Just upstream of Old Maple Avenue	*20
			Just downstream of Velvet Street	*27
			Just upstream of Velvet Street	*33
			0.63 Miles downstreet of Patten Road	*40
			Just upstream of Patten Road	*47
			Downstream side of Old Clintonville Road	*57
			Just upstream of Old Clintonville Road	*62
		Five Mile Brook	Confluence with Muddy River	*24
			Upstream side of footbridge located 0.19 miles upstream of Spring Road.	*32
			0.24 miles upstream of footbridge located 0.19 miles upstream of Spring Road.	*45
			Upstream side of Brook Lane	*59
			Upstream side of Middleton Avenue	*67
			530 feet u/s of Beach Lane	*73
			Downstream side of North Hill Road	*74
		Watermans Brook	Mouth of Quinnipiac River	*11
			Just upstream of Interstate 91	*13
			Downstream side of Elm Street	*20
			Just upstream of Elm Street	*28
			Just upstream of Shawnut Avenue	*33
			Just upstream of St. John Street	*38
			Just upstream of Clintonville Road	*43
			Upstream side of Margo Circle	*46
			Downstream side of Bassett Road	*49
		Pine Brook	Mouth of Quinnipiac River	*17
			Just upstream of Wilbur Cross Parkway	*21
			Just upstream of Hartford Turnpike	*25
			Downstream side of Kings Highway	*37
		Mill River	Upstream side of Whitney Avenue	*54
			Just u/s of Wilbur Cross Parkway	*59
			0.7 Miles u/s of Wilbur Cross Parkway at u/s corporate limit	*63
		Wharton Brook	Confluence with Quinnipiac River	*21
			Just u/s of Private Road	*28
			Just u/s of U.S. Route 5	*33

Maps available at Town Clerk's Office, Town Hall, 3 Lindsey Street, North Haven, Connecticut.

Send comments to: Mr. Walter Gawrych, First Selectmen, Town of North Haven, Town Hall, 3 Lindsey Street, North haven, Connecticut 06473.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(c) Alton, Madison County	Mississippi River	Downstream corporate limit	*437
			Upstream corporate limit	*438
		Coal Branch Creek	Just upstream of North Rodgers Road	*455
			Just upstream of Seminary Road	*465
			Just upstream of Humbert Road	*479
			Confluence with Black Creek	*486
		Belt Line Creek	Downstream corporate limit	*445
			Just upstream of Crest Drive	*446
			Just downstream of State Route 111	*457
		Wood River	Downstream corporate limit	*437
			Upstream corporate limit	*437
		West Fork Wood River	About 0.85 miles downstream of State Highway 140	*439
			Just upstream of State Highway 140	*446
			Just upstream of Burlington Northern Railroad	*449
			Upstream corporate limit	*450

Maps available at: Alton City Hall, 101 East 3rd Street, Alton, Illinois.

Sent comments to: The Honorable Paul Lenz, Mayor, City of Alton, Alton City Hall, 101 East 3rd Street, Alton, Illinois 62002.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(Vlg) Bethalto, Madison County	East Fork Wood River	Approximately 6,865 feet downstream of Albers Lane Road	*451
			Approximately 2,900 feet downstream of Albers Lane Road	*455
			Approximately 1,480 feet downstream of Albers Lane Road	*456

Maps available at: Village Hall, 213 North Prairie Street, Bethalto, Illinois.

Send comments to: Erwin Plegge, Village President, Village of Bethalto, Village Hall, 213 North Prairie Street, Bethalto, Illinois 62010.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(C) Blue Island, Cook County	Stony Creek (East)	Just upstream California Avenue	*582
			About 750 feet downstream Kedzie Avenue	*583
			Just downstream Homan Avenue	*584
			Just downstream Central Avenue	*584

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
		Midlothian Creek	At mouth	*590
			About 1,200 feet downstream of Western Avenue	*592
			Just downstream Western Avenue	*596
			About 900 feet upstream Chicago, Rock Island & Pacific Railroad at corporate limit.	*497
		Little Calumet River	About 2,500 feet downstream of Ashland Avenue	*589
			About 450 feet downstream Chessie System	*590
			Upstream corporate limits	*591

Maps available at: Mayor's Office, City Hall, 13051 South Greenwood Avenue, Blue Island, Illinois.

Send comments to: The Honorable John Rita, Mayor, City of Blue Island, City Hall, 13051 South Greenwood Avenue, Blue Island, Illinois 60406.

Illinois	(V) Cary, McHenry County	Fox River	Southernmost corporate limits	*735
			Mouth of Cary Creek	*736
			Easternmost corporate limits	*736
		Cary Creek	Downstream corporate limits	*754
			About 300 feet downstream from Sewage Plant Road	*756
			Just upstream from Sewage Plant Road	*759
			About 450 feet downstream from concrete footbridge	*774
			100 feet downstream from concrete footbridge	*775
			Just downstream from concrete footbridge	*780
			Just upstream from Cary Street	*801
			Just upstream from Main Street	*806
			Just upstream from Borden Avenue	*806
			About 1,400 feet upstream from Borden Avenue	*817

Maps available at: The Village Administrators Office, Village Hall, 255 Stone Gate, Cary, Illinois.

Send comments to: Mr. Gus Alexakos, Village President, Village of Cary, Village Hall, 255 Stone Gate, Cary, Illinois 60013.

Illinois	(V) Clarendon Hills, DuPage County.	Flagg Creek	Just upstream State route 83	*710
			Just upstream Harris Avenue	*716
			About 830 feet upstream Harris Avenue	*719

Maps available at: The Village Manager's Office, Village Hall 1 North Prospect Avenue, Clarendon Hills, Illinois 60514.

Send comments to: Mr. Philip A. Johnson, Village President, Village of Clarendon Hills, Village Hall, 1 North Prospect Avenue, Clarendon Hills, Illinois 60514.

Illinois	(v)Cleveland, Henry County	Rock River	Western corporate limits	*578
			Eastern corporate limits	*579

Maps available at: Village Hall, Route #1, Colona, Illinois.

Send comments to: The Honorable Joe Merrill, Mayor, Village of Cleveland, Village Hall, Route #1, Colona, Illinois 61241.

Illinois	(C) County Club Hills, Cook County.	North Leg West Branch Cherry Creek.	Downstream corporate limits	*700
			Just downstream Baker Street	*705
		Tributary S	Just upstream mouth at Southwest Branch Calumet Union Drainage Ditch.	*663
			Approximately 250 feet upstream (of sluice gate)	*668
			About 75 feet downstream Clarence Avenue	*673
			Just downstream 183rd Street	*696
			Just upstream 183rd Street	*698
			Approximately 1,760 feet upstream 183rd Street	*701
		Tributary N	Just upstream Crawford Avenue	*657
			Approximately 350 feet upstream 175th Street	*660
			Approximately 920 feet upstream 175th Street	*661
			Just upstream 175th Street	*670
			Approximately 450 feet upstream Anthony Avenue	*673
			Just downstream Cicero Avenue	*680
		Southwest Branch Calumet Union Drainage Ditch.	Downstream corporate limits	*652
			Just downstream Country Club Drive	*654
			Just upstream Country Club Drive	*656
			Approximately 100 feet downstream Cypress Avenue	*661
			Just downstream Kostner Avenue	*671
			Just upstream Kostner Avenue	*676
			About 1,000 feet upstream Kostner Avenue	*678

Maps available at: Administrative Assistant's Office, Village Hall, 3700 West 175th Place, Country Club Hills, Illinois 60477.

Send Comments to: The Honorable David Larson, Mayor, City of Country Club Hills, City Hall, 3700 West 175th Place, Country Club Hills, Illinois 60477.

Illinois	(V) Creve Coeur, Tazewell County	Illinois River	At southern corporate limit	*459
			At northern corporate limit	*459

Maps available at: Village Hall, 101 North Thorncrest, Creve Coeur, Illinois.

Send comments to: Mr. Wayne T. Baker, Village President, Village of Creve Coeur, Village Hall, 101 North Thorncrest, Creve Coeur, Illinois 61611.

Illinois	(V) Dolton, Cook County	Little Calumet River	Western Corporate limit (at Illinois Central Gulf Railroad)	*595
			Just downstream of Cottaghe Grove Avenue	*598
			About 0.21 mile upstream of Interstate 94	*598

Maps available at: Village Hall, 14014 Park Avenue, Dolton, Illinois.

Send comments to: Norman M. MacKay, Village President, Village of Dolton, Village Hall, 14014 Park Avenue, Dolton, Illinois 60419.

Illinois	(V) Flossmoor, Cook County	Butterfield Creek	Just upstream of Dixie Highway	*636
			Just downstream of Vollmer Road	*655
		Butterfield Creek, Tributary No. 1	At confluence with Butterfield Creek	*645

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			Just downstream of Vollmer Road	*652
		Butterfield Creek, Tributary No. 3	At confluence with Butterfield Creek	*652
			Just upstream of Oak Lane Road	*655
			Just upstream of Lake Drive	*658
			Just downstream of Illinois Central Gulf Railroad	*660
		Butterfield Creek Tributary No. 4	At confluence with Butterfield Creek Tributary No. 3	*654
			Just downstream of Oak Lane Road	*656
			Just upstream of Oak Lane Road	*659
			Just downstream of Illinois Central Gulf Railroad	*663
		East Branch Cherry Creek	At northern corporate limit	*664
			Just upstream of Governors Highway	*670
			About 420 feet downstream of Homewood/Flossmoor High School driveway.	*681
			Just downstream of Kedzie Avenue	*685
		East Branch Cherry Creek Tributary.	At confluence with East Branch Cherry Creek	*671
			Just downstream of Governors Highway	*679
		South Leg West Branch Cherry Creek.	At northern corporate limit	*688
			Just downstream of Springfield Road	*694
			Just downstream of Crawford Road	*704

Maps available at: Village Hall, 2800 Flossmoor Road, Flossmoor, Illinois.

Send comments to: The Honorable Bert H. Reed, Jr., Mayor, Village of Flossmore, Village Hall, 2800 Flossmoor Road, Flossmoor, Illinois 60422.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(C) Green Rock, Henry County	Green River	Approximately 450 feet downstream from western corporate limit	*575
			Just upstream from Burlington Northern Railroad	*576
		Rock River	Approximately 2,535 feet downstream from State Highway 84	*575
			Located at State Highway 84	*576

Maps available at City Hall, Colona, Illinois.

Send comments to: The Honorable Danny McDaniel, Mayor, City of Green Rock, City Hall, Colona, Illinois 61241.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(C) Hickory Hills, Cook County	Lucas Ditch Cut-Off	Approximately 1,300 feet downstream 76th Court	*595
			Approximately 270 feet downstream 76th Court	*595
		Local Run-Off (Justice Drainage)	Area around 83rd Avenue and 87th Street	*627

Maps available at: The City Clerk's Office, City Hall, 8652 West 95th Street, Hickory Hills, Illinois 60457.

Send comments to: The Honorable Ervin F. Kozicki, Mayor, City of Hickory Hills, City Hall, 8652 West 95th Street, Hickory Hills, Illinois 60457.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(C) Highland Park, Lake County	Skokie River	Just upstream County Line Road	*632
			Just upstream Clavey Road	*635
			About 700 feet upstream Park Avenue West	*639
			About 1,200 feet upstream Half Day Road	*642
			At upstream corporate limits	*651
		Middle Fork North Branch Chicago River.	At downstream corporate limits	*650
			About 1,000 feet upstream Deerfield Road	*654
			About 1,000 feet upstream Half Day Road at upstream limit of flooding affecting Highland Park.	*659

Maps available at: The City Engineer's Office, City Hall, Highland Park, Illinois.

Send comments to: The Honorable Robert M. Bahai, Mayor, City of Highland Park, City Hall, 1707 St. John's Avenue, Highland Park, Illinois 60035.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(V) Lake Barrington, Lake County	Fox River	At downstream corporate limit	*737
			At upstream corporate limit	*737
		Flint Creek	At confluence with Fox River	*737
			About 0.1 mile downstream of private footbridge	*737
			Just upstream of private footbridge (about 0.37 mile downstream from Kelsey Road bridge).	*747
			Just upstream of Kelsey Road	*747
			Just upstream of Flint Lake Dam	*752
			At confluence of North Arm of Flint Creek	*752
			About 0.4 mile upstream of confluence of North Arm Flint Creek (just downstream of footbridge).	*758
			Just upstream of footbridge	*763
			Just upstream of Illinois Route 22	*764
			Just downstream of U.S. Highway 14	*765
		North Arm of Flint Creek	At confluence with Flint Creek	*752
			Just upstream of Barrington Road	*755
			At upstream corporate limit	*756

Maps available at the Village President's Office, Village Hall, 49 Woodland Drive, Lake Barrington, Illinois.

Send Comments to Mr. Wesley H. Wood, Village President, Village of Lake Barrington, Village Hall, 49 Woodland Drive, Lake Barrington, Illinois 60010.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(V) Lincolnshire	Des Planes River	Southern corporate limit	*646
			Northern corporate limit	*648
		Indian Creek	Mouth at Des Planes River	*648
			About 2,150 feet upstream from mouth (at corporate limits)	*649
			Upstream corporate limits at State Route 22	*653
			About 350 feet upstream of State Route 22 (upstream limit of flooding affecting community).	*655

Maps available at: The Village Manager's Office, Village Hall, 45 Londonderry Lane, P.O. Box Deerfield, Illinois, Lincolnshire, Illinois.

Send comments to: The Honorable Ric Pontenz, Mayor, Village of Lincolnshire, Village Hall, P.O. Box Deerfield, Illinois, 45 Londonderry Lane, Lincolnshire, Illinois 60015.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	Madison, Madison County	Ponding From Rainfall	East of the intersection of 5th Street and Farrish Street	#411

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			At the intersection of Harris Avenue and Farrish Street	#411
			On Caine Drive 1,500 feet east of Farrish Street	#411
			At the intersection of Reynolds Street and Plum Street	#411
			At the intersection of Greenwood Street and Elizabeth Street	#411
			About 1,400 feet west of the intersection of Franklin Street and West Third Street.	#411
			About 1,000 feet west of the intersection of Jackson Street and West Third Street.	#411
			About 2,800 feet west of the intersection of Webster Street and West Third Street.	#411
			At the intersection of Kohl Street and Race Street	#413
			At the intersection of Jackson Street and West Third	#413
		Mississippi River	Southern corporate limit	#430
			Northern corporate limit	#431

Maps available at: City Hall, City Clerk's Office.

Send Comments to The Honorable Mike Sasyk, Mayor, City of Madison, Madison City Hall, 1529 Third Street, Madison, Illinois 62060.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(c)McHenry, McHenry County	Fox River	At the downstream corporate limit	*740
			At the upstream corporate limit	*740
		Boone Creek	Approximately 700 feet downstream of Elm Avenue	*740
			Just upstream of Elm Avenue	*742
			Approximately 150 feet upstream of Mill Stream Drive	*744
			Just upstream of North Drive	*745
			Just upstream of Chicago and North Western Railroad	*750
			Just downstream of State Route 120	*751
			Approximately 300 feet upstream of State Route 120	*753
			Approximately 1,700 feet upstream of State Route 120	*755
			Approximately 450 feet downstream of Oakwood Drive	*760
			Approximately 250 feet downstream of Dam	*763
			Just upstream of Dam	*767
			Approximately 1,200 feet upstream of Dam	*770
		Lakeland-Park Drainage Ditch	Mouth at Boone	*744
			At private Farm Road	*744
			Approximately 1,300 feet upstream of Chicago and North Western Railroad.	*747

Maps available at: The City Clerk's Office, City Hall, 1111 North Green Street, McHenry, Illinois.

Send Comments to The Honorable Joseph B. Stanek, Mayor, City of McHenry, City Hall, 1111 North Green Street, McHenry, Illinois 60050.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(C) Mt. Carmel, Wabash County	Wabash River	Downstream corporate limits	*404
			Upstream corporate limits	*405
		Greathouse Creek	Downstream corporate limit	*404
			About .2 mile upstream State Route 1	*404
			Just upstream State Route 15	*406
			Upstream corporate limit	*407

Maps available at: City Hall, Mt. Carmel, Illinois.

Send comments to: The Honorable George Woodcock, Mayor, City of Mt. Carmel, City Hall, 235 Market Street, Mt. Carmel, Illinois 62863

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	North Pekin, Tazewell County	Illinois River	Approximately 2,700 feet downstream of confluence of Lick Creek	*459
			Approximately 4,000 feet upstream of confluence of Lick Creek	*459
		Lick Creek	Approximately 700 feet upstream of Illinois Central Gulf Railroad	*460
			Approximately 500 feet upstream of State Highway 98	*467
			Approximately 1,050 feet upstream of State Highway 98	*469

Maps available at: The Village Hall, 318 North Main Street, North Pekin, Illinois.

Send comments to: Mr. Thomas K. Conroy, Village President, Village of North Pekin, Village Hall, 318 North Main Street, North Pekin, Illinois 61554.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(v) North Riverside, Cook County	Des Plaines River	1,200 feet upstream of downstream corporate limits	*615
			At the upstream corporate limits	*616
		Addison Creek	Entire reach within corporate limits	*620
		Salt Creek	At confluence of Addison Creek	*620
			Approximately 1,200 feet downstream form 17th Avenue	*620

Maps available at: Village Clerk's Office, Village Hall, 2400 South Avenue, North Riverside, Illinois 60546.

Send comments to: Mr. Richard Vlastnick, Village President, Village of North Riverside, Village Hall, 2400 South Avenue, North Riverside, Illinois 60546.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(v) Old Mill Creek, Lake County	Mill Creek	Approximately 400 feet upstream from eastern corporate limits	*674
			Approximately 4,500 feet upstream from eastern corporate limits	*675
			Approximately 4,600 feet upstream from eastern corporate limits	*678
			Just downstream from Hunt Club Road	*683
			Approximately 1,200 feet upstream from Hunt Club Road	*689
			Approximately 6,400 feet upstream of Hunt Club Road	*690
			Just downstream from the confluence with North Mill Creek	*692
		North Mill Creek	At confluence with Mill Creek	*695
			At the western corporate limit	*698

Maps available at: Village Clerk's Office, Village Hall, 10870 Hunt Club Road, Old Mill Creek, Illinois 60080.

Send comments to: The Honorable Emory Allison, Mayor, Village of Old Mill Creek, Village Hall, 10870 Hunt Club Road, Old Mill Creek, Illinois 60080.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(c) Palos Heights, Cook County	Navajo Creek	About 450 feet downstream of State Route 83	*590
			About 130 feet downstream of State Route 83	*591
			Just upstream State Route 83	*596

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			122nd Street	*599
			Just upstream 122nd Street	*604
			Just downstream Menominee Parkway	*609
			Just upstream Menominee Parkway	*612
			About 175 feet upstream 125th Street	*613
			Just upstream 70th Avenue	*617
			About 640 feet downstream Harlem Avenue	*621
			About 120 feet upstream 76th Avenue	*634
			About 250 feet downstream 131st Street	*641
			About 190 feet downstream 131st Street	*648
		Shallow Flooding (Overflow from storm drains).	At intersection of South 79th and West 130th	#1
		Shallow flooding (Overflow from Forest Preserve Over Levee).	At intersection of South 71st and 130th	#1
			At intersection of South 70th Court and 130th Street	#1

Maps available at: City Hall, Palos Heights, Illinois.

Send comments to: The Honorable William J. Bailey, Mayor, City of Palos Heights, City Hall, 7607 West College Drive, Palos Heights, Illinois 60463.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(v) Olympia Fields, Cook County	Butterfield Creek	Just upstream of Vollmer Road	*654
			Just upstream of Kedzie Avenue	*673
			Just upstream of Illinois Central Gulf Railroad	*676
			Just upstream of Olympian Way	*677
			Just upstream of Governors Highway	*683
			Just upstream of Crawford Avenue	*684
		Butterfield Creek East Branch	At confluence with Butterfield Creek	*682
			Just downstream of Lincoln Highway	*685
		Butterfield Creek Tributary No. 1	At downstream end of retention pond	*655
			At upstream end of retention pond	*655

Maps available at: Village Hall, 207th Street and Route 54, Olympia Fields, Illinois.

Send comments to: Mr. Edmond Burke, Village President, Village of Olympia Fields, Village Hall, 207th Street and Route 54, Olympia Fields, Illinois 60461.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(V) Palos Park, Cook County	Mill Creek	Just upstream 119th Street (Near corporate limit)	*630
			Just downstream 21st Street	*637
			Just upstream 121st Street	*640
			Just downstream 123rd Street	*648
			Just upstream 123rd Street	*652
			Just upstream Southwest Highway	*666
			About 165 feet downstream 131st Street (at corporate limit)	*668
		West Branch Mill Creek	Confluence with Mill Creek	*644
			Just downstream 93rd Avenue	*655
			Just upstream 93rd Avenue	*662
			Just upstream Hobart Avenue	*667
			Upstream corporate limits	*668

Maps available at: Village Hall, 8901 West 123rd Street, Palos Park, Illinois 60464.

Send comments to: The Honorable Rosemary Kaptur, Mayor, Village of Palos Park, Village Hall, 8901 West 123rd Street, Palos Park, Illinois 60464.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(V) Park Forest South, Will County.	Thorn Creek	Cook County-Will County Line	*691
			Approximately 3,600 feet downstream of Monee Road	*705
			Just upstream of Monee Road	*715
			Approximately 2,650 feet upstream of Monee Road	*725
			Just downstream of Exchange Road	*733
			Just upstream of Exchange Road	*736
			Approximately 1,530 feet upstream of Exchange Road	*743
		Deer Creek	Just upstream of the second Western Avenue crossing downstream of Exhange Drive.	*737
			Just upstream of the Western Avenue crossing approximately 633 feet upstream of Exchange Drive.	*739
			Approximately 300 feet upstream of Blackhawk Drive	*742
			Approximately 1,740 feet upstream of Blackhawk Drive	*744
			Upstream corporate limits	*744
		Butterfield Creek East Branch	Downstream corporate limits	*735
			Approximately 400 feet upstream of corporate limits	*738
			At the Will County-Cook County line	*743
			Approximately 500 feet upstream of the Will County-Cook County line.	*746
			Approximately 2,600 feet upstream of the Will County-Cook County line.	*749
			Approximately 3,350 feet upstream the Will County-Cook County line	*756

Maps available at: The Village Hall, 698 Burnham Drive, Park Forest South, Illinois 60466.

Send comments to: Mr. Larry A. McClellen, Village President, Village of Park Forest South, Village Hall, 698 Burnham Drive, Park Forest South, Illinois 60466.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	Pekin, Peoria County and Tazewell County.	Illinois River	Just upstream of Chicago and North Western Railroad	*458
			Approximately 5,000 feet upstream of Peoria and Pekin Union Railroad.	*459
		Lick Creek	Just upstream of State Highway 98	*465
			Approximately 500 feet upstream of State Highway 98	*467
			Approximately 1,050 feet upstream of State Highway 98	*469

Maps available at: The City Hall, 400 Margaret Street, Pekin, Illinois 61554.

Send comments to: The Honorable Willard Berkmier, Mayor, City of Pekin, City Hall, 400 Margaret Street, Pekin, Illinois 61554.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(V) Pontoon Beach, Madison County.	Ponding Due to Local Precipitation Runoff.	Intersection of Tulip Avenue and Marigold Drive	*417
			Tulip Court Cul-De-Sac	*417
			Intersection of Lake Street and South Street	*417

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			Intersection of Bruene Drive and Sunny Side Street	*417
			Intersection of Park Road and Revere Road	*417
			Intersection of Pontoon Avenue and Lake Drive	*417
			Intersection of North Drive and East Lake Drive	*417
			Lake Drive at Southwest Corner of corporate limits	*415
		Long Lake	Eastern corporate limits	*417
			Northern corporate limits	*417
		Horseshoe Lake	Southern corporate limits	*415
			Southeast corporate limits 700 feet south of State Highway 162	*415
Maps available at: Village Hall, 3939 Lake Drive, Pontoon Beach, Illinois.				
Send comments to: The Honorable Paul Bennett, Mayor, Village of Pontoon Beach, Village Hall, 3939 Lake Drive, Pontoon Beach, Illinois 62040.				
Illinois	(v) Riverwoods, Lake County	Des Plaines River	Southern corporate limits	*643
			Northern corporate limits	*644
			0.33 miles upstream of northern corporate limit	*645
		West Fork North Branch	Eastern corporate limit	*665
		Chicago River	Northern corporate limit	*667
Maps available at: Village Hall, Village President's Office, 300 Portwine Road, Riverwoods, Illinois 60014.				
Send comments to: Mr. Ferdinand Rebechini, Village President, Village of Riverwood, Village Hall, 300 Portwine Road, Riverwoods, Illinois 60014.				
Illinois	(v) Round Lake, Lake County	Squaw Creek	Downstream corporate limit	*746
			About 4,200 feet downstream Nippersink Road (at corporate limit)	*746
			About 1,500 feet upstream of Nippersink Road	*760
			About 1,200 feet upstream of Fairfield Road (at corporate limits)	*767
			Just downstream of Cedarlake Road	*770
			Just upstream of Cedarlake Road	*772
			Just downstream Curran Road (at Eastern corporate limits)	*774
		Round Lake Drain	About 175 feet upstream of Grub Hill Road	*747
			About 675 feet downstream of Brentwood Road	*747
		Round Lake	Shore line	*765
Maps available at: Village Clerk's Office, Village Hall, 322 Railroad Avenue, Round Lake, Illinois.				
Send comments to: The Honorable Delbert Amann, Mayor Village of Round Lake, Village Hall, 322 Railroad Avenue, Round Lake, Illinois 60073.				
Illinois	(V) Sauget, St. Clair County	Mississippi River	Southern corporate limit	*425
			Northern corporate limit	*426
		Shallow Flooding (local ponding)	North of Alton & Southern Railway and west of terminal railroad of St. Louis.	*408
			North of Alton & Southern Railway & South of Monsanto Avenue, located at Route 50.	*408
			South of Alton & Southern Railroad and west of Falling Spring Avenue.	*407
			East of Falling Spring Avenue and south of Alton Southern Railway	*407
			Located southeast corporate limit	*406
			South of the northeast corporate limit and 19th Street	*408
			South of the Northern corporate limit and north of Monsanto Avenue	*410
Maps available at: The Village Clerk's Office, Village Hall, 2897 Monsanto Avenue, Sauget, Illinois.				
Send comments to: The Honorable Paul Sauget, Mayor, Village of Sauget, Village Hall, 2897 Monsanto Avenue, Sauget, Illinois 62206.				
Illinois	(V) South Holland, Cook County	Little Calumet River	Approximately 3,000 feet downstream of State Street	*596
			Just downstream of Cottage Grove Avenue	*598
			At western corporate limit	*599
		Thorn Creek	Approximately 1,400 feet upstream of mouth	*599
			Just upstream of Grand Trunk Western Railroad	*602
		Calumet Union Drainage Ditch	Approximately 100 feet upstream of Grand Trunk Western Railroad	*598
			Approximately 1,300 feet upstream of Vincennes Road	*601
Maps available at: The Village Hall, 16226 Wausau Avenue, South Holland, Illinois.				
Send comments to Mr. Harold Gouwens, Village President, Village of South Holland, Village Hall, 16226 Wausau Avenue, South Holland, Illinois 60473.				
Illinois	Spring Bay, Woodford County	Illinois River	Downstream corporate limit	*460
			Upstream corporate limit	*460
Maps available at: 200 Missouri Street, Box 210, Spring Bay, Illinois.				
Send Comments to: Mr. John McCarthy, Village President, Village of Spring Bay, Village Hall, 306 Caroline Street, P.O. East Peroria, Illinois, Spring Bay, Illinois 61611.				
Illinois	Tazewell County	Illinois River	At downstream county boundary	*455
			Just downstream of the Chicago and Northwestern railroad bridge	*458
			Just upstream of the Peroria lock and dam	*459
			Just downstream of the I-24 bridge	*460
			Upstream county boundary	*460
		Mackinaw River	About 2,980 feet downstream of the State Route 29 bridge	*490
			About 1,200 feet upstream the Chicago and Northwestern railroad bridge.	*495
			About 150 feet downstream of the Illinois Central Gulf railroad bridge located 1.46 miles upstream of State Route 29.	*498
			About 1.4 miles upstream of the Illinois Central Gulf Railroad bridge located 1.46 miles upstream of State Route 29.	*502
			About 2.41 miles upstream of the Illinois Central Gulf railroad bridge located 1.46 miles upstream of State Route 29.	*505
			About 1,000 feet downstream of the County Road located 4.2 miles downstream of State Route 9.	*567
			About 1.9 miles downstream of State Route 9	*573
			About 4,220 feet downstream of State Route 9	*577
	(V) Thornton, Cook County	Thorn Creek	Approximately 1,250 feet downstream of Margaret Street	*603

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			Upstream Corporate Limit	*606

Maps available at: Village Clerk's Office, Village Hall, 115 East Margaret Street, Thornton, Illinois.

Send comments to: Mr. Charles P. Nason, Village President, Village of Thornton, Village Hall, 115 East Margaret Street, Thornton, Illinois 60476.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Illinois	(V) Vernon Hills, Lake County	Seavey Drainage Ditch	At downstream corporate limit (about one half mile downstream of Soo Line Railroad.	*673
			Just downstream of Hawthorne Parkway	*683
			Just upstream of Hawthorne Parkway	*685
			At upstream corporate limit	*686

Maps available at: The Village Coordinator's Office, Village Hall, 290 Oakwood Road, Vernon Hills, Illinois.

Send comments to: Mr. John Sullivan, Village President, Village of Vernon Hills, Village Hall, 290 Oakwood Road, Vernon Hills, Illinois 60061.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Indiana	(T) Brooklyn, Morgan County	White Lick Creek	Approximately 1,460 feet downstream of the downstream corporate limit.	*636
			At downstream corporate limits	*637
			Approximately 350 feet downstream of Mill Street	*638
			Just downstream of Mill Street	*639
			Approximately 250 feet upstream of Mill Street	*640
			Approximately 1,300 feet upstream of Mill Street	*641
			Just upstream of upstream corporate limits	*644
			Approximately 700 feet upstream of upstream corporate limit	*645

Maps available at: County Planning Office, County Court House, Martinsville, Indiana.

Send comments to: Mr. Austin B. Wratten, Town Board President, Town Hall, 10 North Main Street, Brooklyn, Indiana 46111, Attention: Catheryn Bennett, Town Clerk.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Indiana	(T) Schneider, Lake County	Kankakee River	About 2,000 feet downstream U.S. Route 41	*634
			About 2,100 feet upstream Conrail	*635

Maps Available at: Town Hall, Schneider, Indiana.

Send comments to: Mr. Jack Lane, President of Town Board, Town of Schneider, Town Hall, Schneider, Indiana 46376

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Indiana	(t) Sellersburg, Clark County	Tributary A of Silver Creek	Within the corporate limits	*469
		Tributary B of Silver Creek	Southeast corporate limits	*465
			Southwest corporate limits	*465
		Camp Run	Southeast corporate limits	*465
			Just upstream of Andres Streat*465	

Maps available at: Town Hall, 316 East Utica Street, Sellersburg, Indiana.

Send comments to: John Werle, Town Board President, Town of Sellersburg, Town Hall, 316 East Utica Street, Sellersburg, Indiana 47172.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Iowa	(c) Dyersville, Dubuque County	North Fork Maquoketa River	1,250 feet downstream of U.S. Highway 20	*937
			Just upstream of U.S. Highway 20	*938
			Just upstream of Third Avenue	*940
			Just upstream of the Illinois Central Gulf Railroad	*943
			1,200 feet upstream of Second Street Northeast	*946
			Northern Corporate Limits	*949
		Bear Creek	Confluence with the North Fork Maquoketa River	*939
			Just upstream of Third Street Southwest	*940
			Just upstream of First Avenue West	*941
			Just upstream of Illinois Central Gulf Railroad	*945
			Just upstream of Chicago and North Western Railroad	*947
			Western Corporate Limits	*948
		Hewitt Creek	At confluence with North Fork Maquoketa River About 1,700 feet upstream of State Highway 136.	*948
		Hewitt Creek	Northern corporate limits	*954
		Hewitt Creek Tributary	At confluence with Hewitt Creek	947
			Just upstream of County Road	*948
			Eastern corporate limit	*963
		Unnamed Creek	At confluence with the North Fork Maquoketa River	*939
			Upstream side of private road	*941
			Just downstream of State Highway 136	*942
			Just upstream of State Highway 136	*952
			Just downstream of U.S. Highway 20	*952
			Just upstream of U.S. Highway 20	*957
			Southeast corporate limits	*957

Maps available at: Coordinator's Office, City Hall, 340 First Avenue East, Dyersville, Iowa 52040.

Send comments to: The Honorable James L. Koch, Mayor, City of Dyersville, City Hall, 340 First Avenue East, Dyersville, Iowa 52040.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Iowa	(C) LaPorte City, Black Hawk County.	Wolf Creek	At downstream corporate limit	*815
			Just downstream of Waterloo railroad	*819
			Just upstream of Chicago, Rock Island, and Pacific Railroad	*823
			Just upstream of U.S. Route 218	*824
			3,000 feet upstream of U.S. Highway 218	*826
			At upstream corporate limit	*826

Maps available at: City Hall, LaPorte City, Iowa.

Send comments to: The Honorable Keith K. Kullmer, Mayor, City of LaPorte City, City Hall, LaPorte City, Iowa 50651.

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Iowa	(c) Leland, Winnebago County	Winnebago River	At the southern corporate limits	*1,215
			Just downstream of County Highway A-38	*1,218
		Drainage Ditch No. 11	Just upstream of Chicago and North Western	*1,216
			At upstream corporate limits	*1,217
Maps available at: City Hall, Leland, Iowa.				
Send comments to: The Honorable John Meyer, Mayor, City of Leland, City Hall, Leland, Iowa 50453.				
Iowa	(C) Mason City, Cerro Gordo County.	Winnebago River	Downstream corporate limits	*1,067
			Upstream side of confluence of Ideal Creek	*1,070
			Just upstream U.S. Highway 18	*1,076
			Just upstream North Illinois Avenue	*1,079
			Upstream side of North Kentucky Avenue	*1,084
			Upstream side of 13th Street	*1,089
			Upstream corporate limits	*1,093
		Mason Creek	Mouth at Winnebago River	*1,068
			2,100 feet upstream of Chicago Milwaukee St. Paul and Pacific Railroad.	*1,070
			3,600 feet upstream of Chicago Milwaukee St. Paul and Pacific Railroad.	*1,075
			3,200 feet downstream of confluence of Tributary M1	*1,080
			1,600 feet downstream of confluence of Tributary M1	*1,085
			200 feet downstream of confluence of Tributary M1	*1,090
			3,400 feet downstream of South Kentucky Avenue	*1,095
			2,000 feet downstream of South Kentucky Avenue	*1,100
			1,200 feet downstream of South Kentucky Avenue	*1,105
			380 feet downstream of South Kentucky Avenue	*1,110
			Approximately 100 feet upstream of South Kentucky Avenue	*1,116
			Just upstream South Virginia Avenue	*1,122
			Upstream side of 19th Street S.E	*1,129
			Just upstream Chicago & North Western Railroad	*1,132
			3,300 feet downstream of Corporate limits	*1,140
			2,100 feet downstream of corporate limits	*1,150
			Upstream side of Chicago & Northwestern Railroad	*1,162
			Upstream Corporate limits	*1,165
		Tributary M1	Mouth at Mason Creek	*1,090
			1,550 feet upstream of mouth	*1,095
			At private road	*1,099
			Upstream corporate limit	*1,109
		Tributary M1-1	Mouth at Tributary M1	*1,090
			Upstream corporate limit	*1,103
		Ideal Creek	Mouth at Winnebago River	*1,069
			Just upstream U.S. Highway 18	*1,070
			1.1 miles upstream of U.S. Highway 18	*1,075
			Just upstream 12th Street N.E	*1,080
			Upstream corporate limits	*1,084
		Willow Creek	Mouth at Winnebago River	*1,084
			1,900 feet upstream of 4th Street N.E	*1,090
			Upstream side of East State Street	*1,097
			Upstream Old Flour Mill Dam	*1,104
			Downstream side of South Pennsylvania Avenue	*1,105
			Upstream Interstate Power Company Dam	*1,113
			Just upstream South Federal Avenue	*1,114
			Just upstream 1st Street S.W	*1,115
			Just upstream North Pierce Avenue	*1,118
			Just upstream abandoned railroad abutments	*1,127
			Just upstream 12th Street N.W	*1,129
			Downstream side of Eisenhower Avenue	*1,139
			Upstream side of Eisenhower Avenue	*1,143
			Upstream of 12th Street N.W. west of Eisenhower Avenue	*1,145
			Upstream side of U.S. Highway 18	*1,159
			Upstream corporate limits	*1,159
		Cheslea Creek	Mouth at Willow Creek	*1,118
			At Willowbrook Drive	*1,123
			Just upstream U.S. Highway 18	*1,126
			Approximately 500 feet upstream 6th Street S.W	*1,130
			Upstream of Chicago, Milwaukee St. Paul, and Pacific Railroad	*1,132
			Just upstream Iowa Terminal Railway	*1,140
			Upstream side of South Benjamin Street	*1,147
			Upstream corporate limits	*1,150
		Calmus Creek	Mouth at Winnebago River	*1,090
			Just upstream Chicago & Northwestern Railroad	*1,095
			Just upstream Federal Avenue	*1,102
			250 feet downstream of Chicago Rock Island and Pacific Railway	*1,112
			Just downstream Lehigh Portland Cement Company Dam	*1,118
			Upstream of Lehigh Portland Cement Company Dam	*1,123
			Just upstream City Road	*1,125
			Upstream corporate limits	*1,127
Maps available at: City Hall, 19 South Delaware, Mason City, Iowa.				
Send comments to: The Honorable Kenneth E. Kew, Mayor, City of Mason City, City Hall, 19 South Delaware, Mason City, Iowa 50401.				
Kansas	(C) Augusta, Butler County	Whitewater River	About 700 feet downstream of U.S. Highway 54	*1,229
			About 700 feet upstream of County Road 618	*1,233
		Elm Creek	Downstream corporate limits	*1,233
			About 75 feet upstream Park Road No. 2	*1,235
			Just upstream Park Road No. 3	*1,248

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			Just downstream Augusta Lake Spillway	*1,254
			Just upstream Augusta Lake Spillway	*1,262
		Walnut River	About 500 feet downstream of Abandoned Bridge (near Osage Street)	*1,225
			About 5,200 feet upstream of Abandoned Bridge (near Osage Street).	*1,226
Maps available at: City Hall, Augusta, Kansas.				
Send commentd to: The Honorable Robert Shryock, Mayor, City of Augusta, City Hall, Augusta, Kansas 67010.				
Kansas	(C) Clearwater	Clearwater Tributary No. 1	At southern most corporate limits	*1,262
			Just upstream of Tracy Avenue South	*1,265
			Just upstream of Missouri Pacific Railroad	*1,267
			Just upstream of Ross Avenue	*1,269
			Just upstream of Grant Avenue	*1,273
			Just upstream of Tracy Avenue North	*1,279
Maps available at: City Hall, Clearwater, Kansas.				
Send comments to: The Honorable Eugene C. Greenlee, Mayor, City of Clearwater, City Hall, Clearwater, Kansas.				
Kansas	(C) Kechi, Sedgwick County	Middle Fork Chisholm Creek	At downstream corporate limits	*1,367
			Just upstream 61st Street Bridge	*1,372
			At upstream corporate limits	*1,373
Maps available at: City Hall, 200 Kechi Road, Kechi, Kansas 67067.				
Send comments to: The Honorable Andrew Arkaness, Mayor, City of Kechi, City Hall, 200 Kechi Road, Kechi, Kansas 67067.				
Kansas	(C) Kingman, Kingman County	South Fork Ninnescah	At downstream corporate limits	*1,500
			Just downstream of Main Street	*1,505
			Just upstream of Main Street	*1,508
			250 feet upstream of corporate limit	*1,511
		Salt Creek	100 feet downstream of Atchison, Topeka and Santa Fe Railway bridge (near sewage disposal plant).	*1,503
			Just upstream of Atchison, Topeka and Santa Fe Railway (near Avenue A).	*1,508
			Just upstream of Avenue D	*1,514
		Pocomo Creek	At confluence with South Fork Ninnescah River	*1,509
			Just upstream of Broadway Street	*1,520
			Just upstream of Avenue H	*1,528
			Just upstream of confluence of West Fork Pocomo Creek	*1,539
			500 feet downstream of Kansas Avenue (at upstream limit of detailed study).	*1,554
Maps available at: The City Hall, 324 North Main, Kingman, Kansas.				
Send comments to: The Honorable Claude Wallace, Mayor, City of Kingman, City Hall, P.O. Box 168, Kingman, Kansas 67068.				
Kansas	(C) Lansing, Leavenworth County.	Missouri River	Southeastern corporate limit	*770
			Northeastern corporate limit	*771
		Sevenmile Creek	Downstream corporate limits	*770
			About 1,400 feet upstream of confluence of Sevenmile Creek Tributary.	*771
			About 200 feet downstream U.S. Highway 73	*785
			Just upstream U.S. Highway 73	*792
			Approximately 2,500 feet upstream of U.S. Highway 73	*795
			Upstream corporate limits	*822
		Sevenmile Creek Tributary	Confluence with Sevenmile Creek	*771
			Approximately 1,750 feet upstream of confluence with Sevenmile Creek.	*771
			Just upstream of Atchison Topeka and Santa Fe Railway	*778
			Approximately 6,700 feet upstream of Atchison Topeka and Santa Fe Railway.	*794
		Ninemile Creek	Downstream corporate limit	*771
			About 2,000 feet upstream State Highway 5 (near County Road)	*772
			Just upstream of County Road	*775
			Approximately 4,200 feet upstream of East Mary Street	*787
			Just downstream of County Road (near U.S. Highway 73)	*799
			Just upstream of County Road (near U.S. Highway 73)	*807
			About 200 feet upstream of southern corporate limits	*814
Maps available at: City Hall, Lansing, Kansas.				
Send comments to: The Honorable John Adams, Mayor, City of Lansing, City Hall, 108 South Main, Lansing, Kansas 60043.				
Kansas	Leavenworth County	Missouri River	Downstream county boundary	*765
			Just upstream Burlington Northern	*773
			Upstream county boundary	*782
		Sevenmile Creek	Confluence with Missouri River	*768
			State Highway 5	*771
		Kansas River	About 0.7 miles downstream of county boundary	*782
			Just upstream DeSoto Road	*791
			Just upstream county road near Eduora, Kansas	*806
			Upstream county boundary	*815
		Tonganoxie Creek	About 1,040 feet upstream of County Road 1847	*834
			Just upstream of Washington Street	*843
			Just upstream of U.S. Highway 24	*859
			About 4,060 feet upstream of U.S. Highway 24	*863
		Dawson Creek	Confluence with Stranger Creek	*894
			Just upstream of Third Street	*904
			About 4,250 feet upstream of Kickapoo Street	*916
		Ninemile Creek	Confluence with Stranger Creek	*799
			About 5,740 feet upstream of County Road	*801

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
		Stranger Creek	Confluence with Kansas River	*796
			Just upstream of State Highway 32	*799
			About 6,520 feet upstream of State Highway 32	*801
			About 600 feet upstream of confluence with Cramer Creek	*892
			Just upstream State Highway 192	*904
			About 5,370 feet upstream of State Highway 192	*906

Maps available at: Planning and Zoning Department, Leavenworth County Courthouse, Leavenworth, Kansas 66048.

Send comments to: Mr. Howard Vining, Chairman, County Board of Commissioners, Leavenworth County Courthouse, Leavenworth, Kansas 66048.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Maine	Baldwin (T),	Saco River Cumberland County	Downstream corporate limits	*263
			Just downstream State Route 117	*281
			Just downstream Hiram Falls Dam	*291
			Just upstream Hiram Falls Dam	*352
			Upstream corporate limits	*359
		Quaker Brook	Confluence with Saco River	*265
			About 400 feet downstream of Maine Central Railroad	*265
			About 380 feet upstream of State Route 113	*271
		Pigeon Brook	Confluence with Saco River	*271
			Just upstream of River Road	*297
			About 1,600 feet upstream of Maine Central Railroad	*325
			About 370 feet upstream of State Route 113	*369
		Pigeon Brook Tributary	Confluence with Pigeon Brook	*272
			About 200 feet downstream of Chase Siding Road	*291
			About 80 feet upstream of Chase Siding Road	*298
		Dug Hill Brook	Confluence with Saco River	*285
			About 1,300 feet upstream from confluence with Saco River	*285
			Just upstream State Route 113	*314
			About 1,370 feet upstream of State Route 113	*331
		Breakneck Brook	Confluence with Sanco River	*287
			About 2,000 feet upstream from confluence with Saco River	*287
			Just upstream Maine Central Railroad	*335
			Just downstream Old State Route 113	*358
			Just upstream Douglas Hill Road (downstream of Wards Hill Road)	*438
			Just upstream Farm Drive	*490
			About 70 feet upstream of Douglas Hill Road (near Davis Road)	*541

Maps available at: Town Office, East Baldwin, Main.

Send comments to: Mr. Norman McKenney, First Selectman, Town Office, East Baldwin, Maine 04024.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Maine	(t) Denmark, Oxford County	Saco River	Downstream corporate limit	*366
			Confluence with Dragon Meadow Brook	*368
			Approximately 20,000 feet upstream of confluence of Moose Pond Brook.	*371
			Approximately 5,500 feet downstream of upstream corporate limits	*373
			Upstream corporate limits	*374
			Pleasant Pond	*378

Maps available at: Town Office, Denmark, Maine.

Send Comments to: Mr. Elden W. Burnell, First Selectmen, Town of Denmark, Town Office, Denmark, Maine 04022.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Maine	(T) Monmouth, Kennebec County.	Cobbosseecontee Lake	Shoreline	*170
		Annabessacook Lake	Shoreline	*173
		Cochnewagon Lake	Shoreline	*272
		Wilson Pond	Shoreline	*245
		Sand Pond	Shoreline	*178
		Woodbury Pond	Shoreline	*178

Maps available at: The Town Office, Monmouth, Maine.

Send comments to Mr. Robert Smith, Town Manager, Town of Monmouth, Town Office, Monmouth, Maine 04259.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Massachusetts	(T) Charlemont, Franklin County	Deerfield River	Just upstream of the New England Power Dam Number 4	*480
			Just upstream of State Route 2 first crossing	*482
			Approximately 1.52 miles upstream of State Route 2 first crossing	*486
			Approximately 2.97 miles upstream of State Route 2 first crossing	*501
			Approximately 3.77 miles upstream State Route 2 first crossing	*510
			Approximately 4.73 miles upstream of State Route 2 first crossing	*520
			Approximately 2.16 miles downstream of West Hawley Road	*530
			Approximately 1.28 miles downstream of West Hawley Road	*540
			Approximately .38 mile downstream of West Hawley Road	*550
			Approximately .51 mile upstream of West Hawley Road	*560
			Approximately 1.34 mile upstream of West Hawley Road	*570
			Just upstream of State Route 2 second crossing	*574
			Approximately .49 mile downstream of the Boston and Maine Railroad	*581
			Just downstream of the Boston and Maine Railroad	*595
			Just upstream of the Boston and Maine Railroad	*597
		Bozrah Brook	Mouth at Deerfield River	*553
			Approximately 560 feet upstream of mouth	*553
			Approximately 1,640 feet upstream of mouth	*563
			Approximately 500 feet downstream of the upstream corporate limit	*580
			Upstream corporate limit	*594
		Legate Hill Brook	Mouth at Deerfield River	*555
			Approximately 2,100 feet upstream of mouth	*559
			Approximately 1,061 feet downstream of Legate Hill Road	*561

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			Just downstream of Legate Hill Road	*567
			Upstream side of Legate Hill Road (limit of detailed study)	*569

Maps available at: Selectmen's Office, Town Hall, Charlemont, Massachusetts 01339.

Send comments to: Mr. William Harker, Chairman, Board of Selectmen, Town Hall, Main Street, Charlemont, Massachusetts 01339.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Massachusetts	(T) Colrain, Franklin County	North River	Gaging station in Shattuckville	*471
			Approximately one-mile downstream of State Route 112 bridge in Griswoldville.	*483
			Approximately one-half mile downstream of State Route 112 bridge in Griswoldville.	*491
			Just upstream of State Route 112 bridge in Griswoldville	*504
			Just upstream of Adamsville Road	*509
			Approximately 0.2 mile upstream of Adamsville Road	*512
			Just downstream of dam	*517
			Just upstream of dam	*526
			At confluence of North River West Branch	*526
		North River East Branch	Approximately one—third mile downstream of Lyonsville Road	*528
			Just upstream of Lyonsville Road	*533
			Approximately 0.02 mile upstream of Foundry Brook	*535
			Approximately 0.2 mile downstream of Foundry Village Road	*543
			Just downstream of Foundry Village Road	*553
			Just upstream of Foundry Village Road	*559
			Approximately 0.4 mile upstream of Foundry Village Road	*575
			Just upstream of State Route 112 bridge in Colrain	*596
			Approximately one-half mile upstream of State Route 112 bridge in Colrain.	*604
			Approximately one-third mile downstream of Reils Road	*615
			Just downstream of Reils Road	*624
		North River West Branch	At confluence with North River East Branch	*526
			Approximately one eighth mile downstream of Adamsville Road	*531
			Just upstream of Adamsville Road	*534
			Just downstream of Dam	*538
			Just upstream of Dam	*546
			Just downstream of Hersig Road	*560
			Just upstream of Hersig Road	*563
			Approximately 0.2 mile downstream of Heath Road	*576
			Just downstream of Heath Road	*586
			Just upstream of Heath Road	*591
			Approximately 0.32 mile upstream of Heath Road	*608
			Approximately 0.31 mile downstream of Maxam Road	*633
			Just downstream of Maxam Road	*648
			Just upstream of Maxam Road	*650
			Approximately 0.1 mile upstream Maxam Road	*662
		Foundry Brook	At confluence with North River East Branch	*535
			Just upstream of Foundry Village Road	*549
			Approximately 0.015 mile upstream of Foundry Village Road	*553
			Approximately 0.020 mile upstream of Foundry Village Road	*560
			Approximately 0.04 mile upstream of Foundry Village Road	*561
			Approximately 0.05 mile upstream of Foundry Village Road	*563
			Approximately 0.08 mile upstream of Foundry Village Road	*568
			Approximately 0.093 mile upstream of Foundry Village Road	*574
			Approximately 0.010 mile upstream of Foundry Village Road	*576

Maps available at: Town Hall, Colrain, Massachusetts.

Send comments to: Mr. Duane Scranton, Chairman, Board of Selectmen, Town Hall, Colrain, Massachusetts 01340.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Massachusetts	(T) Dracut, Middlesex County	Merrimack River	Downstream Corporate Limit	*52
			Upstream Corporate Limit	*59
		Beaver Brook	Downstream Corporate Limits	*70
			Just downstream from Pleasant Street	*70
			Just upstream from Pleasant Street	*78
			600 feet upstream from Parker Avenue	*80
			700 feet upstream from Parker Avenue	*85
			2,500 feet upstream from Phineas Street	*92
			1,700 feet downstream from Lakeview Avenue	*96
			400 feet downstream from Lakeview Avenue	*100
			Just upstream from Lakeview Avenue and dam	*119
			Just downstream of Corrine Drive	*121
			Upstream corporate limits	*124
		Peppermint Brook	Just upstream from Lakeview Avenue	*70
			100 feet upstream from Sladen Street	*73
			100 feet downstream from Pleasant Street	*75
			Just upstream from Pleasant Street	*81
			Just upstream from Hildreth Street	*82
		Richardson Brook	Just upstream from Merrimack Avenue	*56
			600 feet upstream from Merrimack Avenue	*56
			950 feet upstream from Merrimack Avenue	*60
			300 feet downstream from Methuen Street	*72
			Just downstream from Methuen Street	*74
			90 feet upstream from Methuen Street	*79
		Gumpas Pond Brook	Confluence with Beaver Brook	*124
			Northwest corporate limits	*124

Maps available at: The Building Inspector's Office, Town Hall, 52 Arlington Street, Dracut, Massachusetts.

Send comments to: Mr. Brendon Delany, Chairman, Board of Selectmen, Town of Dracut, Town Hall, 52 Arlington Street, Dracut, Massachusetts 01826.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Massachusetts	(T) Greenfield, Franklin County	Allen Brook	At confluence with Green River	*170
			Just upstream of Plain Road	*178

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			About 300 feet upstream of Colrain Road	*220
		Hinsdale Brook	At confluence with Green River	*182
			Just upstream of Plain Road	*191
			Just upstream of Snead Hill Road	*245
		Connecticut River	At confluence of Deerfield River	*142
			Just upstream of Turners Falls Road bridge	*152
			At confluence of Fall River	*158
		Deerfield River	At confluence with Connecticut River	*142
			At upstream corporate limit	*142
		Cherry Rum Brook	At confluence with Green River	*168
			At outlet end of Interstate 91 culvert	*189
			At inlet end of Interstate 91 culvert	*200
			At confluence of Mill Brook	*210
			Just upstream of Boston and Main railroad	*239
			Just downstream of Cherry Rum Brook Dam No. 2	*250
			Just upstream of Cherry Rum Brook Dam No. 2	*256
			Just upstream of culvert entrance at Gold Street	*262
			About 500 feet upstream of Cherry Street	*263
		Green River	At confluence with Deerfield River	*142
			Just upstream of dam near Meridian Street	*144
			Just downstream of dam near Mill Street	*148
			Just upstream of Mill Street	*153
			Just upstream of Interstate	*167
			At confluence of Allen Brook	*170
			At confluence of Glen Brook	*191
			Just upstream of Eunice Williams Drive	*245
		Fall River	Mouth at Connecticut River	*158
			Just upstream of South Cross Road	*158
			Just downstream of Old Stone Dam	*194
			Just upstream of Old Stone Dam	*204
			Just upstream of Bascom Road	*248
			At upstream corporate limit	*277

Maps available at: The Planning Office, Town Hall, Greenfield, Massachusetts.

Send comments to: Mr. Frank Yetter, Chairman, Board of Selectmen, Town Hall, Greenfield, Massachusetts 01301.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Massachusetts	(T) Methuen, Essex County	Bare Meadow Brook	Just down stream of Merrimack Street	*28
			At confluence of Hawkes	*28
		Hawkes	Appoximately 1,100 feet upstream of confluence with Bare Meadow Brook.	*28
			Approximately 2,600 feet upstream of confluence with Bare Meadow Brook.	*39
			Approximately 3,800 feet upstream of confluence with Bare Meadow Brook.	*75
		Spicket River	Just upstream of southern corporate limit	*60
			Just downstream of dam at Lowell Street	*76
			Just upstream of dam at Lowell Street	*107
			Just upstream of Hampshire Road	*112
		Harris Brook	At confluence with Spicket River	*111
			Approximately 2,000 feet downstream of Salem Street	*113
			Approximately 1,000 feet downstream of Salem Street	*118
			Just upstream of Pelham Street	*143
			Just upstream of Hampshire Road	*145
		Merrimack River	Approximately 0.4 mile downstream of Interstate Route 495	*28
			Approximately 2.8 miles upsteam of Interstate Route 495	*34
			Approximately 1 mile downstream of Interstate Route 93	*49
			Approximately 2.8 miles upstream of Interstate Route 93	*52

Maps available at: Community Development Office, Town Municipal Office, 90 Hampshire Street, Methuen, Massachusetts 01844.

Send comments to: Town Council, President, Town Municipal Office, 90 Hampshire Street, Methuen, Massachuetts 01844.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Massachusetts	(T) Shelburne, Franklin County	Deerfield River	Just upstream New England Power Company Dam No. 3	*411
			About 80 feet upstream State Route 2	*424

Maps available at: Town Offices, 51 Bridge Street, Shelburne, Massachusetts.

Send comments to: Mr. Harry S. Zaluzny, Chairman, Board of Selectmen, Town Offices, 51 Bridge Street, Shelburne Massachusetts 01370.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Massachusetts	(c) Woburn, Middlesex County	Aberjona River	Downstream Corporate Limits	*31
			Approximately 175 feet upstream of Montvale Avenue	*38
			Just upstream of Washington Street	*41
			Just upstream of Central Street	*43
			Just upstream of Salem Street	*46
			Just upstream of Olympia Avenue	*49
			Just downstream of Nomac Road	*50
			Just upstream of Mishawum Road	*52
			Just downstream of the downstream Commerce Way crossing culvert.	*54
			Just upstream of the downstream Commerce Way crossing culvert	*60
			Just upstream of the Commerce Way crossing located approximately 800 feet downstream of Commonwealth Avenue.	*63
			Just upstream of Interstate 95	*66
			Approximately 825 feet upstream of Interstate 95	*67
		Halls Brook	Just upstream of the upstream Merrimack Street crossing	*107
			Approximately 400 feet upstream of the upstream Merrimack Street crossing.	*107
		Schneider Brook	At confluence with Alberjona River	*43
			Just downstream of the access road located approximately 1,025 feet upstream of the confluence with the Aberjona River.	*50
			Approximately 580 feet downstream of the downstream end of the Washington Street and Salem Street culvert.	*53

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county.	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			At the downstream end of the Washington Street and Salem Street culvert.	*61
			At the upstream end of the Washington Street and Salem Street culvert.	*74
			Just downstream of Forbes Street	*80
			Just upstream of Forbes Street	*84
			Approximately 825 feet upstream of Forbes Street	*84
		Horn Pond Brook	At downstream corporate limits	*38
			Just downstream of Pond Street	*41
			Just upstream of Pond Street	*44
		Fowle Brook	Approximately 80 feet downstream of Aqueduct Road	*44
			Just upstream of Aqueduct Road	*45
			Approximately 1,600 feet upstream of Aqueduct Road	*47
		Shaker Glen Brook	Just downstream of Totman Drive	*48
			Just upstream of Lexington Street	*52
			Just downstream of Cambridge Road culvert	*55
			Just upstream of Cambridge Road	*63
			Approximately 1,400 feet upstream of Russell Street	*64
			Approximately 2,700 feet upstream of Russell Street	*85
			Approximately 3,900 feet upstream of Russell Street	*105
			Approximately 4,725 feet upstream of Russell Street	*119
		Cummings Brook	At confluence with Fowle Brook	*47
			Just upstream of Lexington Street	*49
			Just downstream of the Locust Street culvert	*57
			Just upstream of Locust Street	*63
			Just downstream of Bedford Street	*70
			Just upstream of Bedford Street	*74
			Just upstream of Willow Road	*78
			Just downstream of Burlington Street	*78
			Just upstream of Burlington Street	*84
			Just upstream of Bamberg Drive	*91
			Just downstream of Sheridan Street	*92
			Just upstream of Sheridan Street	*97
			Just downstream of Winn Street	*99
			Approximately 80 feet upstream of Winn Street	*102
		Little Brook	At confluence with Cummings Brook	*69
			Approximately 1,450 feet downstream of Bedford Road	*75
			Approximately 90 feet downstream of Bedford Road	*89
			Just upstream of Bedford Road	*96
			Approximately 800 feet upstream of Bedford Road	*103

Maps available at: The Planning Board Office, City Hall, 10 Common Street, Woburn, Massachusetts.

Send comments to: The Honorable Thomas M. Higgins, Mayor, City of Woburn, City Hall, 10 Common Street, Woburn, Massachusetts 01801.

Michigan	(c) Burton, Genesee County	Phillips Drain	Downstream Corporate limits	*780
			At access culvert	*782
			Just upstream from Atherton Road	*784
			Just upstream from Eugene Road	*791
			Upstream corporate limits	*797
		Kearsely Creek	Downstream corporate limits	*743
			Approximately 5,000 feet upstream from corporate limits	*745
			Approximately 1,500 feet downstream from Belsay Road	*749
			Just upstream from Belsay Road	*751
			Just upstream from Farm Road	*753
			Approximately 3,000 feet downstream from Davison Road	*756
			Just upstream from Davison Road	*759
			At upstream corporate limits	*762
		Gilkey Creek	Downstream corporate limits	*755
			Just upstream from Grand Trunk Western Railroad	*757
			Just upstream from upstream Grand Trunk Western Railroad	*758
			Just upstream from Genesee Road	*761
			Just upstream from Court Street	*762
			Just upstream from Lapeer Road	*764
			Just upstream from Genesee Road	*766
			Just upstream from Roat Court	*768
			Just upstream from Lippincott Boulevard	*768
			Approximately 1,200 feet upstream from Lippincott Boulevard	*771
			Approximately 3,300 feet upstream from Lippincott Boulevard	*774
			Just upstream from Private Road	*779
			Just upstream from Atherton Road	*781
			Just downstream from Sitra Street	*790
			Just upstream from Sitra Street	*794
			Just upstream from Belsay Road	*796
			Just upstream from Bellingham Court	*797
			Approximately 600 feet upstream from Bellingham Court	*798
			Just upstream from Brigtol Road	*800
			Just downstream from Hazel Road	*804
			Just upstream from Hazel Road	*806
		Thread Creek	Approximately 1,950 feet downstream Corporate limits	*760
			Just downstream from Term Street	*762
			Just upstream from Atherton Road	*766
			Approximately 3,500 feet upstream from Atherton Road	*768
			Just downstream from Bristol Road	*772
			Just upstream from Bristol Road	*773
			Approximately 4,000 feet upstream from Bristol Road	*778
			Approximately 7,000 feet upstream from Bristol Road	*782
			Upstream corporate limit (Maple Avenue)	*788
		Gibson Drain	Located at downstream corporate limit (Fenton Road)	*760
			Just downstream from Schumacher Street	*763

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			Just upstream from Schumacher Street	*767
			Just downstream from Judd Road	*768
			Just upstream from Judd Road	*769
			Located at upstream corporate limit (Maple Avenue)	*771

Maps available at City Engineer's Office, City Hall, Burton, Michigan.

Send comments to: The Honorable Richard L. Wurtz, Mayor, City of Burton, City Hall, 4303 South Center Road, Burton, Michigan 48519.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Michigan	(T) Clayton, Genesee County	Messmore Cronk Drain	Just upstream of Potter Road	*722
			About 100 feet upstream of a private road which is about 800 feet upstream of Potter Road.	*723
			Approximately 1,800 feet upstream of Potter Road	*725
			Approximately 3,400 feet upstream of Potter Road	*730
			Approximately 100 feet upstream of a private road which is about 2,000 feet downstream of Beecher Road.	*733
			Approximately 1,000 feet downstream of Beecher Road	*735
			Approximately 50 feet upstream of Beecher Road	*738
			Approximately 60 feet downstream of Elms Road	*740
		Cole Creek	Just upstream of Potter Road	*716
			Approximately 2,800 feet upstream of Potter Road	*720
			Approximately 1 mile upstream of Potter Road	*726
			Approximately 2,600 feet downstream of Beecher Road	*730
			Approximately 700 feet downstream of Beecher Road	*735
			Approximately 100 feet upstream of Beecher Road	*739
			Approximately 3,800 feet upstream of Beecher Road	*745
			Just upstream of a private road which is about 850 feet downstream of the northernmost Morrish Road crossing.	*750
			Just downstream of the Morrish Road crossing which is 1,200 feet downstream of Calkins Road.	*752
			Just upstream of Calkins Road	*754
			Approximately 50 feet downstream of the Morrish Road crossing which is about 2,800 feet upstream of Calkins Road.	*757
			Approximately 1,000 feet downstream of Corunna Road	*760
			Just upstream of Corunna Road	*762
			Approximately 400 feet upstream of a private road which is about 2,150 feet upstream of Corunna Road.	*763
			Approximately 300 feet downstream of Lennon Road	*765

Maps available at: Township Hall, 2011 South Morrish Avenue, Swartz Creek, Michigan.

Send comments to: Mr. John R. Fick, Township of Supervisor, Township of Clayton, Township Hall, 2011 South Morrish Avenue, Swartz Creek, Michigan 48473.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Michigan	(C) Clio, Genesee County	Pine Run	At western corporate limits	*687
			Just upstream of Chessie System Railroad bridge	*691
			Just downstream of Center Street	*692
			Just upstream of Center Street	*695
			Just upstream of Clio Road	*696
			Just upstream of Vienna Road	*696
			Confluence of Mason Drain	*698
			Approximately 730 feet upstream from the confluence of Mason Drain	*699
			At eastern corporate limits	*702
		Mason Drain	At confluence of Pine Run	*698
			Approximately 1,000 feet upstream from confluence of Pine Run	*699
			Approximately 500 feet downstream from southern corporate limits	*701
			At southern corporate limits	*704

Maps available at: City Hall, 200 Griffes Street, Clio, Michigan.

Send comments to: The Honorable Samuel Geddes, Mayor, City of Clio, City Hall, 200 Griffes Street, Clio, Michigan 48420.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Michigan	(V) Dimondale, Eaton County	Grand River	Northern corporate limits	*844
			Southern corporate limits	*847
		Old Maid Drain	Mouth	*845
			Western corporate limits	*845

Maps available at: The Village Clerk's Office, P.O. Box 26, Dimondale, Michigan.

Send comments to: Ms. Norma Fredlied, Village Clerk, Village of Dimondale, P.O. Box 26, Dimondale, Michigan 48821.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Michigan	(c) East Grand Rapids, Kent County.	Reeds Lake	Shoreline	*734
		Fisk Lake	Shoreline	*734

Maps available at: City Hall, 750 Lakeside Drive, S.E., East Grand Rapids, Michigan.

Send comments to: Mr. Clifford McMann, City Engineer, City of East Grand Rapids, City Hall, 750 Lakeside Drive, S.E., East Grand Rapids, Michigan 49506.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Michigan	(C) East Lansing, Ingham County.	Red Cedar River	Approximately 450 feet upstream Aurelius Road	*836
			Approximately 1,500 feet upstream Hagadorn Road	*841

Maps available at: City Hall, 410 Abbot Road, East Lansing, Michigan.

Send comments to: Mr. Gordon Melvin, City Engineer, City of East Lansing, City Hall, 410 Abbot Road, East Lansing, Michigan 48823.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Michigan	(C) Grand Blanc, Genesee County.	Thread Creek	About 1,450 feet downstream of Center Road	*805
			Just upstream of Center Road	*809
			Just upstream of Rust Pork Drive	*810
			Just upstream of Old Bridge Street	*814
			Just upstream of Genesee Road	*819
			Just upstream of confluence of Bush Creek	*823
			Upstream corporate limit near Balsay Road	*825
			About 1,250 feet upstream of corporate limit near Balsay Road	*826

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Maps available at: The City Hall, 227 East Grand Blanc Road, Grand Blanc, Michigan.				
Send comments to: Mr. Gordon Manboyr, City Manager, City of Grand Blanc, City Hall, 227 East Grand Blanc Road, Grand Blanc, Michigan 48439.				
Michigan	(Twp) Grand Blanc, Genesee County.	Swartz Creek	Downstream corporate limit (near Ann Maria Drive)	*827
			About 0.5 mile downstream of Baldwin Road (at corporate limit)	*831
			About 5,000 feet upstream of Baldwin Road (at corporate limit)	*839
		Gibson Drain	Downstream corporate limit	*774
			Just upstream of Interstate 475	*777
			Just upstream of Wishing Well Drive	*783
			Just upstream of Russell Street	*787
			At downstream end of culvert near Rollins Street	*793
			At upstream end of culvert south of Hill Road	*801
			About 0.40 mile downstream of Porter Road	*807
			Just upstream of Porter Road	*812
			About 0.62 mile upstream of Porter Road	*813
		Eamas Drain	Mouth at Seaver Drain	*842
			About 1,500 feet downstream of Baldwin Road	*860
			Just dounstream of Baldwin Road	*862
		Seaver Drain	Just upstream of Fenton Road	*826
			Just upstream of Cook Road	*834
			Just upstream of private road located about 2,500 feet upstream of Cook Road.	*838
			About 2,500 feet downstream of confluence of Eames Drain (near private road).	*839
			About 1,400 feet upstream of MeWain Road	*843
		Thread Creek	Just upstream of Maple Avenue	*790
			About 3,300 feet downstream of Hill Road	*795
			Just upstream of Chessie System (south of Hill Road)	*803
			Corporate limits (about 700 feet upstream of Center Road)	*809
			About 100 feet upstream of Genesee Road	*819
			Just upstream of Belsay Road	*828
			About 250 feet upstream of confluence of Day Drain	*833
			About 300 feet upstream of Perry Road	*838
Maps available at: The Township Hall, 5371 South Saginaw Street, Grand Blanc, Michigan.				
Send comments to: Mr. William Delaney, Township Supervisor, Township of Grand Blanc, 5371 South Saginaw Street, Grand Blanc, Michigan.				
Michigan	(Twp) Grosse Ile, Wayne County	Detroit River	Northern to Southern Corporate Limits	*578
		Thoroughfare Canal	From confluence to confluence of Detroit River	*578
		Frenchman Creek	3,800 feet upstream from Grott Road to confluence of Detroit River	*578
Maps available at: Township Hall, 8841 Macomb Street, Grosse Ile, Michigan.				
Send comments to: Mr. Dallas S. Kelsey, Township Supervisor, Township of Grosse Ile, Township Hall, 8841 Macomb Street, Grosse Ile, Michigan 48138.				
Michigan	Laketown, Allegan County	Lake Michigan	Shoreline	*584
		Hults Lake	Shoreline	*624
		Goshorn Lake	Shoreline	*617
		Lake Tibbie	Shoreline	*607
Maps available at: Township Hall, A-6242 West 144th Street, Holland, Michigan				
Send comments to: Mr. Dan Koeman, Township Clerk, Township of Laketown, Township Hall, A-6242 West 144th Street, Holland, Michigan, 49423.				
Michigan	(Twp) Montrose, Genesee County	Armstrong Creek	About 2,000 feet downstream of McKinley Road	*635
			Just upstream of McKinley Road	*639
			About 3,000 feet upstream of McKinley Road	*647
			About 3,000 feet downstream of Dodge Road	*656
			Just upstream of Dodge Road	*662
			About 3,000 feet upstream of Dodge Road	*668
			About 3,000 feet downstream of Morrish Road	*673
			Just upstream of Morrish Road	*678
			Just downstream of Frances Road	*679
Maps available at: The Township Hall, Montrose, Michigan.				
Send comments to: Mr. Tom Casteel, Township Supervisor, Township of Montrose, Township Hall, Box 36, Montrose, Michigan 48457.				
Michigan	(c) Mount Clements, Macomb County.	Clinton River	Downstream corporate limit	*581
			Just downstream Gratiot Avenue	*585
			Just downstream Grand Trunk & Western Railroad	*589
			Upstream corporate limit	*591
Maps available at:City Manager's Office, City Hall, 1 Crocker Blvd., Mount Clements, MI.				
Send comments to:The Honorable Bert VandeVusse, Mayor, City of Mount Clements, City Hall, 1 Crocker Boulevard, Mount Clements, MI 48043.				
Michigan	(V) New Haven, Macomb County	Salt River	At the downstream corporate limit	*603
			At the upstream corporate limit	*618
		Shook River	At the confluence with Salt River	*604
			Just downstream of Amvet Drive	*606
			About 100 feet upstream of Amvet Drive	*608
			About 100 feet upstream of Victoria Street	*624
			About 100 feet downstream of Clark Street	*631
			Just downstream of Clark Street	*636
			At the upstream corporate limit	*644
Maps available at: The Village Hall, 58725 Havenridge Road, New Haven, Michigan.				
Send comments to: Mr. George Drake, Village President, Village of New Haven, Village Hall, 58725 Havenridge Road, New Haven, Michigan 48048.				

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Michigan	(Twp) St. Joseph, Berrien County.	St. Joseph River	At downstream corporate limits of St. Joseph Township	*584
			About 1,056 feet upstream of Napier Avenue	*584
			About 8,900 feet upstream of Napier Avenue	*587
			Upstream corporate limit of St. Joseph Township	*588
		Hickory Creek	At downstream corporate limits of St. Joseph Township	*585
			About 100 feet downstream of Niles Road	*586
			About 100 feet upstream of Niles Road	*587
			About 700 feet upstream of Niles Road	*587
			About 760 feet downstream of Washington Avenue	*588
			About 200 feet downstream of Washington Avenue	*588
			About 100 feet upstream of Washington Avenue	*589
			About 100 feet upstream of Cleveland Avenue	*590
			About 3,350 feet upstream of Cleveland Avenue	*591
			Just downstream of Maiden Lane	*593
			At upstream corporate limit of St. Joseph Township	*594
		Lake Michigan	Shoreline	*584

Maps available at: The Township Hall, 146 West Napier, Benton Harbor, Michigan.

Send comments to: Mr. Isadora DiMaggio, Treasurer, Township of St. Joseph, Township Hall, 146 West Napier, Benton Harbor, Michigan 49022.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Michigan	(c) Wayne, Wayne County	Bingell Drain	Just downstream of Michigan Avenue Westbound Lanes	*655
			Just upstream of Michigan Avenue Eastbound Lanes	*658
			Approximately 550 feet downstream of Hannan Road	*660
			Just downstream of Hannan Road	*662

Maps available at: City Hall, Building Department, 34808 Simms Street, Wayne, Michigan.

Send comments to: The Honorable Paul Lada, Mayor, City of Wayne, City Hall, 34808 Simms Street, Wayne, Michigan 48184.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Michigan	(Twp) White River, Muskegan County.	Lake Michigan	Shoreline	*584
		White Lake	Shoreline	*584

Maps available at: Township Hall, White River, Michigan.

Send comments to: Mr. Robert C. Wachemagel, Township Supervisor, Township of White River, Township Hall, White River, Michigan 49437.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Michigan	(C) Ypsilanti, Washtenaw County	Huron River	Just downstream of Interstate 94	*686
			Approximately 2,000 feet downstream of Michigan Avenue	*691
			Approximately 300 feet upstream of Conrail	*703
			Just downstream of the Peninsular Dam	*707
			Just upstream of the Peninsular Dam	*718
			Just upstream of Superior Road	*720
		Paint Creek	Just upstream of Interstate 94	*755
			Just downstream of Michigan Avenue	*756

Maps available at: The Community Development Department, City Hall, 304 North Huron Street, Ypsilanti, Michigan.

Send comments to The Honorable George D. Goodman, Mayor, City of Ypsilanti, City Hall, 304 North Huron Street, Ypsilanti, Michigan 48197.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Minnesota	(C) Glencoe, McLeod County	Buffalo Creek	About 2,800 feet downstream of southeast corporate limit	*989
			About 1,300 feet downstream of Hennepin Avenue	*990
			About 450 feet upstream of southwest corporate limit	*992

Maps available at: City Hall, 804 East 11th Street, Glencoe, Minnesota 55336.

Send comments to the Honorable Elf Austad, Mayor, City of Glencoe, City Hall, 804 East 11th Street, Glencoe, Minnesota 55336.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Minnesota	(c) Ham Lake, Anoka County	Coon Creek	Western corporate limits	*879
			Approximately 0.8 mile upstream from western corporate limits	*880
			Just upstream from State Highway 65	*882
			Approximately .13 mile upstream from Raddison Street	*885
			Just downstream from County Ditch No. 11	*888
			Approximately 0.3 mile downstream from Naples Street	*889
			Just upstream from Naples Street	*892
			Just downstream of Lexington Avenue	*893
		Deer Creek	Confluence with Coon Creek	*887
			Just downstream from Bunker Lake Boulevard	*891
			Just upstream from Bunker Lake Boulevard	*894
			Upstream corporate limits	*895

Maps available at: City Hall, 15544 Central Avenue, N.E., Anoka, Minnesota.

Send comments to: The Honorable Eldon He, Mayor, City of Ham Lake, City Hall, 15544 Central Avenue, N.E., Anoka, Minnesota 55303.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Minnesota	(C) Inver Grove Heights, Dakota County.	Mississippi River	Downstream corporate limit	*698
			Upstream corporate limit	*703

Maps available at: City Hall, 8650 Court House Boulevard, Inver Grove Heights, Minnesota.

Send comments to The Honorable Calvin Blonquist, Mayor, City of Inver Grove Heights, City Hall, 8650 Court House Boulevard, Inver Grove Heights, Minnesota 55075, Attention: Robert Schafer, City Administrator.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Minnesota	(C) Jackson, Jackson County	West Fork Des Moines River	Southern downstream corporate limits	*1,306
			Just downstream of dam near Ashley Street	*1,308
			Just upstream Ashley Street	*1,310
			Just upstream of U.S. Highway 71	*1,313
			Upstream corporate limits	*1,314

Maps available at: City Hall, 504 2nd Street, Jackson, Minnesota 56043.

Send comments to: The Honorable Arvin Schultz, Mayor, City of Jackson, City Hall, 504 2nd Street, Jackson, Minnesota 56043, Attention: David Hartley, City Administrator.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Minnesota	Lac Qui Parle County	Lac Qui Parle River	Just upstream of U.S. Highway 212	*1,039
			Just downstream of Chicago and North Western Railroad	*1,044

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			Just upstream of Chicago and North Western Railroad	*1,045
			7,000 feet upstream of Chicago and North Western Railroad	*1,946
		West Branch Lac Qui Parle River	Confluence with Lac Qui Parle River	*1,042
			Eastern corporate limit, City of Dawson	*1,043
			Western corporate limit, City of Dawson	*1,048
			7,200 feet upstream of western corporate limit, City of Dawson	*1,049
			14,700 feet downstream of U.S. Highway 212	*1,065
			Just downstream of U.S. Highway 75	*1,069
			Just upstream of U.S. Highway 75	*1,070
			2,900 feet upstream of U.S. Highway 75	*1,071

Maps available from: Ray Olsen, County Auditor, County Courthouse, Auditor's Office, Madison, Minnesota 56121.

Send comments to: Mr. Alfred Gloege, Chairman of the Board, Lac Qui Parle County, County Courthouse, Madison, Minnesota 56212.

Minnesota	(c) Long Prairie, Todd County	Long Prairie River	At the downstream corporate limit	*1,283
			Just downstream of Lake Street	*1,289
			Just upstream of First Avenue Northeast	*1,291
			At the upstream corporate limit	*1,292
		Venewitz Creek	At the confluence with Prairie River	*1,291
			Just downstream of Second Avenue Southwest	*1,291
			Just upstream of Third Avenue Southwest	*1,293
			Just downstream of First Street Southwest	*1,294

Maps available at: City Hall, Long Prairie, Minnesota.

Send comments to: The Honorable Don Moore, Mayor, City of Long Prairie, City Hall, 239 Central Avenue, Long Prairie, Minnesota 56347.

Minnesota	(C) Medina, Hennepin County	Elm Creek	Approximately 105 feet downstream from Highway 55	*959
			Just upstream from Highway 55	*959
			Just downstream from State Highway 101	*962
			Just upstream from State Highway 101	*964
			Just downstream from Access Road	*966
			Just upstream from Access Road	*973
			Just downstream from Soo Line Railroad	*973
			Just upstream from Soo Line Railroad	*975
			Approximately 300 feet upstream from Elm Creek Drive	*977
			Just downstream from upstream crossing of Soo Line Railroad	*978
		Lake Independence	Shoreline within Medina	*960
			At mouth	*961
		Unnamed Tributary	Located at Lake Shore Avenue	*961
			At Ardmore Street	*961
		Lake Ardmore	Shoreline within Medina	*962

Maps available at: City Hall, 2052 County Road 24, Hamel, Minnesota.

Send comments to: The Honorable Thomas Anderson, Mayor, City of Medina, City Hall, 2052 County Road 24, Hamel, Minnesota 55340.

Minnesota	Newport, Washington County	Mississippi River	Downstream corporate limits	*703
			Upstream corporate limits	*705

Maps available at: The Newport City Hall, 596 7th Avenue, Newport, Minnesota.

Send comments to: The Honorable Basil Loveland, Mayor, City of Newport, Newport City Hall, 596 7th Avenue, Newport, Minnesota 55055, Attention: Mr. John Hawes, City Clerk Administrator.

Minnesota	(C) Randolph, Dakota County	Chub Creek	Downstream corporate limit	*864
			Just upstream Dixie Avenue	*868
			Just downstream Cooper Avenue	*874
			Upstream corporate limit	*875
		Cannon River	Just downstream State Route 56	*861
			Just downstream County Road 83	*865
			Approximately .25 mile upstream County Road 83	*870
			Upstream limit of flooding affecting community	*871

Maps available at: City Hall, P.O. Box 67, Randolph, Minnesota.

Send comments to: The Honorable Arnold Ziemer, Mayor, City of Randolph, City Hall, P.O. Box 67, Randolph, Minnesota 55065.

Minnesota	(C) Sobieski, Morrison County	Swan River	At the downstream corporate limit	*1,112
			Just upstream of County Road 222	*1,119
			At the upstream corporate limit (about 1,000 feet downstream County Highway 18).	*1,123

Maps available at: The City Hall, Little Falls, Minnesota.

Send comments to: The Honorable Leo Frank, Mayor, City of Sobieski, City Hall, Route 3, Box 178, Little Falls, Minnesota 56345.

Minnesota	City of Waterville, Le Sueur County.	White Water Creek	Just downstream State Highway 13	* 1,004
			Just upstream of State Highway 13	* 1,008
			Just upstream Hoosac Street	* 1,011
			Just downstream Reed Street	* 1,013
			Upstream corporate limits	* 1,018
		Lake Sakatah	Shoreline	* 1,004
		lake Tetonka	Shoreline	* 1,005
		Shallow flooding	Intersection of Harmon Street and Buchannan Street	# 1.0
		(overflow from White Water Creek).	Intersection of Paquin Street and Herbert Street	# 1.0

Maps available at: City Hall, Waterville, Minnesota, 56096.

Send comments to: The Honorable Lawrence Meskan, Mayor, City of Waterville, City Hall 201, 3rd Street, South, P.O. Box 9, Waterville, Minnesota, 56096.

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Missouri	(C) Birch Tree, Shannon County	Birch Creek	Downstream Corporate Limit	*980
			About 320 feet downstream First Street	*982
			Just upstream Park Street	*985
			Just downstream Main Street	*986
			About 100 feet upstream Ozark Street	*990
			About 150 feet downstream U.S. Highway 60	*997
			Just downstream U.S. Highway 60	*1,000
Maps available at: City Hall, Birch Tree, Missouri.				
Send comments to: The Honorable Leonard M. Layman, Mayor City of Birch Tree, City Hall, Birch Tree, Missouri 65438.				
Missouri	City of Crane, Stone County	Crane Creek	Just downstream Missouri Pacific Railroad	*1,109
			Downstream Corporate Limits	*1,111
			Approximately 140 feet upstream State Highway 13	*1,118
			Just upstream Roundhouse Road	*1,122
			Upstream Corporate Limits	*1,129
		Dodge Hollow	At confluence with Crane Creek	*1,116
			Approximately 100 feet upstream State Highway 13	*1,118
			Upstream Corporate Limits	*1,124
Maps available at: City Hall, Crane, Missouri, 65633.				
Send comments to: The Honorable V. E. Spears, Mayor City of Crane, City Hall, Crane, Missouri, 65633.				
Missouri	(C) Ellington, Reynolds County	Logan Creek	At downstream corporate limits	*652
			Just upstream of State Highway 21	*657
			Just downstream from Main Street	*661
			Approximately 4,200 feet downstream from upstream corporate limits	*668
			At upstream corporate limits	*676
		Dickson Creek	At downstream corporate limits	*652
			Just downstream of State Highway 21	*656
			Just downstream of Second Street	*666
			About 100 feet downstream of Main Street	*670
			About 450 feet upstream of Main Street	*671
			At upstream corporate limits	*727
Maps available at: The City Hall, P.O. Box 7, Ellington, Missouri.				
Send comments to: The Honorable Euel Polk, Mayor, City of Ellington, City Hall, P.O. Box 7, Ellington, Missouri, 63638.				
Missouri	(v) Hanley Hills, St. Louis County	Northeast Branch River Des Peres.	Downstream corporate limits	*543
			About 2,100 feet upstream Raft Drive	*544
			About 2,550 feet upstream Raft Drive	*545
Maps available at: City Hall, 7713 Utica Street, Hanley Hills, Missouri.				
Send comments to: Miss Carol Wilhelm, Chairperson of the Board, City Hall, 7713 Utica Street, Hanley Hills, Missouri 63183.				
Missouri	Mountain View (c), Howell County	Jamup Creek	Approximately 80 feet upstream County Road	*1,098
			At St. Louis-San Francisco Bridge	*1,106
			Just downstream Jackson Street	*1,120
			Just downstream Marr Street	*1,124
			Just upstream Marr Street	*1,125
			Approximately 600 feet upstream Marr Street	*1,126
			Approximately 80 feet upstream Missouri Highway West	*1,130
			Just upstream Missouri Highway 17	*1,136
			Approximately 325 feet upstream Missouri Highway 17	*1,136
			Upstream corporate limits	*1,145
Maps available at: City Hall, Mountain View, Missouri.				
Send Comments to: The Honorable Joanne Smith, Mayor, City of Mountain View, City Hall, Mountain View, Missouri 65548.				
Missouri	Rock Port, Atchison County	Rock Creek	Downstream Corporate Limit	*925
			Approximately 800 feet downstream of Cass Street	*929
			Just upstream from Cass Street	*932
			Upstream Corporate Limit	*935
Maps available at: City Hall, Rockport, Missouri.				
Send comments to: The Honorable Frank Heyen, Mayor, City of Rock Port, City Hall, Rock Port, Missouri 64482.				
Nebraska	(c) of Fairbury, Jefferson County	Little Blue River	About 1.2 miles downstream from confluence of Brawner Creek	*1,292
			Just downstream of State Highway 15	*1,301
			Just upstream of Chicago, Rock Island and Pacific Railroad	*1,306
			Just upstream of Frederick Street	*1,312
			About 1,500 feet upstream of U.S. Highway 136	*1,323
			About 1.2 miles upsteam of abandoned Rock Island and Pacific railroad, at upsteam limit of study.	*1,330
		Brawner Creek	At confluence with Little Blue River	*1,299
			About 850 feet downstream Union Pacific Railroad	*1,300
			Just upstream of Fairgrounds Road	*1,326
			Just downstream of Chicago, Rock Island, and Pacific Railroad	*1,350
			Just upstream of U.S. Highway 136	*1,363
			About 0.60 mile upstream of U.S. Highway 136	*1,367
			Just downstream of County Road	*1,387
			Just upstream of County Road	*1,393
			Just downstream Soil Conservation Service Dam	*1,400
			Just upstream Soil Conservation Service Dam	*1,415
			0.68 miles above Soil Conservation Service Dam	*1,416

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			Just downstream of County Road (0.8 mile above dam)	*1,419
			Just upstream of County Road (0.8 mile above dam)	*1,427
			At northern extraterritorial limit	*1.443

Maps available at: City Hall, 612 D Street, Fairbury, Nebraska.

Send comments to: The Honorable Robert F. Lammers, Mayor, City of Fairbury, City Hall, 612 D Street, Fairbury, Nebraska 68352.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Nebraska	(c) Seward, Seward County	Big Blue River	Upstream side of County Road J3G34	*1,436
			Upstream side of Second Street	*1,444
			Upstream side of State Highway 127	*1,449
			Upstream side of County Road G817	*1,452
			About 2.1 miles upstream County Road G817	*1,456
		Plum Creek	Confluence with Big Blue River	*1442
			Upstream side of Hillcrest Drive	*1,450
			About .25 miles upstream County Road G1015	*1,458
			About 2.4 miles upstream County Road G1015	*1,465

Maps available at: City Hall, P.O. Box 38, Seward, Nebraska.

Send comments to: The Honorable Steve Korinko, Mayor, City of Seward, City Hall, P.O. Box 38, Seward, Nebraska 68434.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Nebraska	(v) South Bend, Cass County	Platte River	1,600 feet upstream of Chicago, Rock Island, and Pacific Railroad	*1,039
			At corporate limits 4,100 feet upstream of Chicago, Rock Island, and Pacific Railroad.	*1,040
			6,500 feet upstream of Chicago, Rock Island, and Pacific Railroad	*1,043

Maps available at: Chairman's home, P.O. box 222, South Bend, Nebraska, 68058.

Send comments to Mr. L. M. Snodgrass, Chairman of the Village Board, Village of South Bend, P.O. Box 222, South Bend, Nebraska 68058.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Nebraska	(c) West Point, Cuming County	Elkhorn River	Approximately 8,900 feet downstream of State Highway 32	*1,300
			Approximately 1,200 feet downstream of confluence of unnamed tributary South of West Point.	*1,303
			Approximately 1,800 feet downstream of State Highway 32	*1,305
			Just upstream of State Highway 32	*1,308
			Approximately 3,400 feet upstream of State Highway 32	*1,310
			Approximately 6,900 feet upstream of State Highway 32	*1,311
		Unnamed Creek South of West Point.	At confluence with Elkhorn River	*1,304
			Just upstream of Farm House Entrance Road	*1,305
			Approximately 800 feet downstream of Chicago and North Western railroad.	*1,310
			Just upstream of Chicago and North Western railroad	*1,316
			Approximately 100 feet upstream of Main Street	*1,318
			Approximately 80 feet upstream of U.S. Highway 275	*1,323
			Approximately 600 feet upstream of U.S. Highway 275	*1,328
			Approximately 1,150 feet upstream of U.S. Highway 275	*1,333
		Overflow from unnamed creek south of West Point.	Southwest Portion of City	#1

Maps available at: The City Office, 201 South Main, West Point, Nebraska.

Send comments to: The Honorable Michael R. Wortman, Mayor, City of West Point, City Office, 201 South Main, West Point, Nebraska 68788.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
New Hampshire	(T) Greenville, Hillsborough County.	Souhegan River	900 feet downstream of Boston and Maine railroad	*710
			Just upstream of Boston and Maine railroad	*718
			Just upstream of Main Street	*729
			1,200 feet upstream of Main Street	*735
			100 feet downstream of Mill Street	*758
			Downstream side of dam No. 6	*770
			Upstream side of dam No. 6	*789
			Just downstream of dam No. 4	*790
			Upstream side of dam No. 4	*809
			Downstream side of dam No. 1	*809
			Upstream side of dam No. 1	*829
			Upstream corporate limit	*829
		Tributary A	Confluence with Souhegan River	*744
			Upstream side of Mill Street	*752
			Just downstream of Old Mason Road	*753

Maps available at: The Town Office, Main Street, Greenville, New Hampshire.

Send comments to: Ms. Rose Marie Plante, Chairperson, Board of Selectmen, Town of Greenville, Town Office, Main Street, Greenville, New Hampshire 03048.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
New Hampshire	(T) Holderness, Grafton County	Pemigewasset River	At the Southern Corporate Limit	*485
			At the Northern Corporate Limit	*490
		Owl Brook	Just upstream of State Route 175	*736
			Approximately 1,800 feet upstream of State Route 175	*763
			Just downstream of Perch Pond Road	*793
			Just upstream of Perch Pond Road	*798
		Beede Brook	Just downstream of School Road	*737
			Just upstream of School Road	*740
			Just downstream of Perch Pond Road	*742
			Approximately 400 feet upstream of Perch Pond Road	*746

Maps available at: The Town Office, Holderness, New Hampshire.

Send comments to: Mr. Donald E. Dana, Chairman, Board of Selectmen, Town Office, Holderness, New Hampshire 03425.

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
New Hampshire	(t) New Boston, Hillsborough County.	Middle Branch Piscataquog River.	At mouth	*345
			Just downstream of Riverdale Road	*352
			Just upstream of Riverdale Road	*357
			Upstream side of Abandoned Saw Mill Dam	*362
			Northern corporate limit about 1.2 miles upstream of Abandoned Saw Mill Dam.	*368
			Northern corporate limit about 1.0 mile downstream of State Route 77	*372
			0.27 mile downstream of State Route 77	*383
			Just downstream of State Route 77	*404
			0.32 mile upstream of State Route 77	*408
			100 feet downstream of Dougherty Lane	*425
			Just upstream of Dougherty Lane	*433
			Just downstream of Tucker Mill Dam	*444
			Just upstream of Tucker Mill Dam	*466
			Just upstream of Sanders Hill Road	*470
			Just downstream of Breached Mill Dam No. 1	*476
			Just upstream of Breached Mill Dam No. 1	*484
			0.4 mile upstream of Breached Mill Dam No. 1	*490
			0.3 mile downstream of Breached Dam No. 2	*505
			Just downstream of Breached Dam No. 2	*519
			Just upstream of Breached Dam No. 2	*526
			Just downstream of East Colburn Road	*535
		South Branch Piscataquog River..	Eastern corporate limit	*309
			Just upstream of Parker Road	*321
			0.83 mile upstream of Parker Road	*330
			Just upstream of Gregg Mill Road	*347
			0.86 mile upstream of Gregg Mill Road	*360
			0.45 mile downstream of Todd Road	*375
			Just upstream of Todd Road	*386
			0.4 mile upstream of Todd Road	*400
			Just upstream of Depot Street	*411
			Downstream side of the Merrimack Farmers Exchange Dam	*418
			Just upstream of Merrimack Farmers Exchange Dam	*424
			422 feet downstream of State Route 13	*430
			Upstream side of State Route 13	*434
	Main Branch Piscataquog River		Just upstream of Parker Road	*297
			0.53 mile upstream of North Mast Road	*298
Maps available at: Town Hall, New Boston, New Hampshire.				
Send comments to: Mr. Roland Sallada, Chairman, Board of Selectmen, Town of New Boston, Town Hall, New Boston, New Hampshire 03070.				
Ohio	(V) Amberley, Hamilton County	Section Road Creek	At the downstream corporate limits	*590
			Just downstream of Section Road	*593
			Just upstream of Fair Oaks Avenue	*602
			About 400 feet upstream from Fair Oaks Avenue	*603
			Approximately 300 feet downstream of West Beechland Drive	*624
			Just upstream of West Beechland Drive	*633
			Just downstream of Ridge Road	*636
		Left Fork of Section Road Creek..	At confluence with Section Road Creek	*592
			Just downstream of the private drive located approximately 460 feet upstream of mouth.	*596
			Just upstream of private drive located approximately 300 feet downstream of Fair Oaks Drive.	*602
			Just upstream of Fair Oaks Drive	*613
			Just upstream of Meadowbrook Drive	*617
			Just upstream of the Private Drive located approximately 250 feet upstream of Meadowbrook Drive.	*621
			Just upstream of the upstream crossing of Willowbrook Drive	*623
			Just downstream of the Private Drive located approximately 465 feet downstream of Aracoma Forrest Drive.	*634
			Just upstream of the Private Drive located approximately 465 feet downstream of Aracoma Forrest Drive.	*639
			Just downstream of Aracoma Forrest Drive	*642
		Brookwood Creek	At inlet to pipe enclosure located approximately 1,080 feet downstream of Fair Oaks Drive.	*607
			Just downstream of Fair Oaks Drive	*617
		Brookwood Creek (shallow flooding overflow).	From inlet to pipe enclosure located approximately 1,080 feet downstream of Fair Oaks Drive to downstream corporate limits.	#2
Maps available at: Village Hall, 7149 Ridge Road, Amberley, Ohio.				
Send comments to: The Honorable Arthur H. Friedman, Mayor, Village of Amberley, Village Hall, 7149 Ridge Road, Amberley, Ohio 45237.				
Ohio	(C) Amherst, Lorain County	Beaver Creek	About 1 mile downstream Cooper-Foster-Park Road near corporate limit.	*592
			About 1,400 feet downstream Cooper-Foster-Park Road	*594
			About 100 feet downstream Martin Avenue	*620
			Just upstream Martin Avenue	*624
			Just downstream Milan Avenue	*632
			About 4,200 feet upstream confluence of Tributary No. 1	*644
			Just downstream Middle Ridge Road	*667
			Upstream Corporate Limit	*679
		Tributary No. 1	At confluence with Beaver Creek	*640
			About 130 feet upstream Crown Hill Avenue	*652
			Just downstream Pyle-South Amherst Road	*652

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			About 180 feet upstream Pyle Road	*668
			Just upstream Middle Ridge Road	*724
			About 900 feet upstream Middle Ridge Road	*728
		East Branch Beaver Creek	Just upstream Cleveland Western Road	*620
			About 270 feet downstream State Route 2	*629
			About 1,000 feet upstream State Route 2	*632
			About 50 feet downstream North Ridge Road	*645
			Just upstream Private walk (near low head dam)	*652
			Just upstream Park Avenue	*676
Maps available at: City Hall, 206 Main Street, Amherst, Ohio.				
Send comments to: The Honorable Anthony DePaola, Mayor, City of Amherst, City Hall, 206 Main Street, Amherst, Ohio 44001.				
Ohio	(C) Belpre, Washington County	Ohio River	About 400 feet upstream from Grandee Avenue	*609
			About 1,940 feet upstream from Memorial Bridge	*610
Maps available at: City Hall, 201 Washington Street, Belpre, Ohio.				
Send comments to: The Honorable Ivan Smith, Mayor, City of Belpre, City Hall, 201 Washington Street, Belpre, Ohio 45714.				
Ohio	(v) Bentleyville, Cuyahoga County	Chagrin River	About 100 feet upstream of Miles Road	*822
			About 100 feet downstream of mouth with Aurora Branch	*827
			At eastern corporate limits	*836
		Aurora Branch	Just upstream of mouth of Tributary No. 2	*883
			Just downstream of confluence with Tributary No. 1	*889
			About 100 feet downstream of Norfolk and Western Railway	*891
			At southern corporate limits	*892
		Tributary No. 1	About 300 feet upstream of mouth with Aurora Branch	*890
			At southern corporate limits	*894
		Tributary No. 2	About 360 feet downstream of Liberty Road	*884
			About 100 feet upstream of Liberty Road	*895
			About 270 feet upstream of mouth of Tributary No. 4	*940
			About 50 feet upstream of Salon Road	*960
			At southern corporate limits	*9SS
Maps available at: Village Hall, 6253 Cagrin River Road, Bentleyville, Ohio 44022.				
Send comments to: The Honorable Robert DeFranco, Mayor, Village of Bentleyville, Village Hall, 6253 Chagrin River Road, Bentleyville, Ohio 44022.				
Ohio	(V) Beverly, Washington County	Muskingum River	Southeast corporate limits	*637
			Northwest corporate limits	*638
Maps available at: Village Hall, P.O. Box 725, Beverly, Ohio.				
Send comments to: The Honorable Carl Kane, Mayor, Village of Beverly, Village Hall, P.O. Box 725, Beverly, Ohio 45715.				
Ohio	(C) Blue Ash, Hamilton County	Hazelwood Creek	Just upstream Kenwood Road	*821
			About 1,700 feet downstream Idalia Avenue	*824
			About 950 feet downstream Idalia Avenue	*829
			Just upstream Idalia Avenue	*834
			Just downstream Cornell Road	*842
		Raiders Run	Downstream corporate limit	*780
			About 210 feet downstream Bellview Avenue	*780
			Just upstream Bellview Avenue	*793
			Just downstream Cross County Highway	*802
Maps available at: The Office of Clerk of Counsel, 4343 Cooper Road, Blue Ash, Ohio.				
Send comments to: Mr. Victor Suhm, City Manager, City of Blue Ash, 4343 Cooper Road, Blue Ash, Ohio 45242.				
Ohio	(V) Cedarville, Greene County	Massies Creek	Southwestern corporate limit	*968
			Just downstream Cedarville-Yellowsprings Road	*1,017
			Just upstream Bridge Street	*1,029
			Just upstream Main Street	*1,031
			Just upstream of Cedarville Dam	*1,033
		North Fork Massies Creek	Just upstream South Street	*1,035
		South Fork Massies Creek	Upstream corporate limit (Conrail)	*1,034
Maps available at: The Office of Village Clerk, Cedarville, Ohio 45314.				
Send comments to: The Honorable Warren Weber, Mayor, Village of Cedarville, East Xenia Road, Cedarville, Ohio 45314.				
Ohio	(C) Chagrin Falls, Cuyahoga County.	Chagrin River	Downstream corporate limit	*836
			About 1,400 feet downstream Miles Road	*846
			About 2,250 feet upstream Miles Road	*869
			About 3,900 feet upstream Miles Road	*886
Maps available at: City Hall, Chagrin Falls, Ohio.				
Send comments to: The Honorable James Solether, Mayor, City of Chagrin Falls, City Hall, Chagrin Falls, Ohio 44022.				
Ohio	(V) Clifton Greene & Clark Counties.	Little Miami River	Just downstream Wilberforce-Clifton Road	*987
			Just downstream dam	*994
			Just upstream dam	*1,000
			About 550 feet upstream of dam	*1,002
Maps available at: The Office of Village Clerk, Village Hall, Clifton, Ohio.				
Send comments to: The Honorable Jack Estridge, Mayor, Village of Clifton, 5 Clay Street, Clifton Ohio 45316.				

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Ohio	(V) Corwin, Warren County	Little Miami River Mill Run Channel.	About 960 feet downstream of Corwin Road	*724
Maps available at: The Village Hall, Corwin, Ohio.				
Send comments to: The Honorable Howard Purkey, Mayor, Village of Corwin, Village Hall, Corwin, Ohio, 75068.				
Ohio	(C) Elyria, Lorain County	East Branch Black River	Just upstream of dam near Washington Avenue	*690
			Just downstream of dam near East Broad Street	*701
			Just upstream of dam near East Broad Street	*710
			About 5,400 feet upstream of East Fourth Street	*719
		West Branch Black River	Just downstream of Lake Avenue	*683
			Just upstream of Third Street	*701
			Just upstream of Mussey Avenue	*716
			Upstream corporate limits	*722
		Shallow Flooding (ponding from Tributary 1)	Just upstream Griswold Road	*688
			Just downstream Midway Boulevard	*688
		Shallow Flooding (overflow from Tributary 1)	Just upstream State Highway 57	#1
			Just upstream Norfolk and Western Railway	#1
Maps available at: The Office of the Clerk of Council, 328 Broad Street, Elyria, Ohio.				
Send comments to: Mr. Lonny Shippy, City Engineer, City of Elyria, 328 Broad Street, Elyria, Ohio 44035.				
Ohio	(C) Girard, Trumbull County	Mahoning River	At downstream corporate limit	*852
			At upstream corporate limit	*857
Maps available at: City Hall, 100 West Main Street, Girard, Ohio.				
Send comments to: The Honorable Nick D'Eramo, Mayor, City of Girard, City Hall, 100 West Main Street, Girard, Ohio 44420.				
Ohio	(C) Grandview Heights, Franklin County.	Overflow from Scioto River	Goodale Boulevard at east corporate limits	*723
			Intersection of Burrell Avenue and Higgs Avenue	*725
			Intersection of Goodale Boulevard and Copeland Road	*727
			Intersection of Goodale Boulevard and Quay Avenue	*730
			Intersection of Goodale Boulevard and Grandview Avenue	*733
		Olentangy River	Just upstream of Conrail bridge over Twin Rivers Drive	*722
			About 0.5 mile upstream of Conrail bridge	*723
		Scioto River	At corporate limits about 0.45 mile downstream Grandview Avenue	*729
			At corporate limits about 0.32 mile downstream Grandview Avenue	*730
Maps available at: The Municipal Building, 1016 Grandview Avenue, Grandview Heights, Ohio.				
Send comments to: The Honorable Lawrence E. Peice, Mayor, City of Grandview Heights, Municipal Building, 1016 Grandview Avenue, Grandview Heights, Ohio 43212.				
Ohio	(V) Green Springs, Sandusky & Seneca Counties.	Flag Run	Downstream corporate limits	*670
			Just downstream Broadway Street	*679
			Just upstream Broadway Street	*684
			Just downstream Conrail (Abandoned)	*687
			Upstream corporate limit	*691
		Tributary to Flag Run	At confluence with Flag Run	*691
			Upstream corporate limits	*691
Maps available at: Office of the Village Clerk, Box 536, Green Springs, Ohio.				
Send comments to: The Honorable John Burkette, Mayor, Village of Green Springs, 315 Academy Street, Box 355, Green Springs, Ohio 44836.				
Ohio	(v) Hudson, Summit County	Brandywine Creek	Approximately 1,160 feet downstream of Lake Forest Dam	*984
			Just downstream of Lake Forest Dam	*997
			Just upstream of Lake Forest Dam	*1,003
			Just downstream of Ingleside Drive	*1,005
			Just downstream of Pine Lake Dam	*1,010
			Just upstream of Pike Lake Dam	*1,021
			Approximately 200 feet upstream of Atterbury Boulevard	*1,022
			Just downstream of Conrail	*1,025
			Just downstream of West Prospect Street	*1,029
			Approximately 440 feet upstream of confluence of Brandywine Creek Tributary No. 1.	*1,031
			Just downstream of Owen Brown Street	*1,044
			Just downstream of Morse Road	*1,047
			Just upstream of Ravennu Street	*1,053
			Approximately 100 feet downstream of South Oviatt Street	*1,061
		Brandywine Creek Tributary No. 1	Mouth at Brandywine Creek	*1,031
			Approximately 1,000 feet upstream of mouth at Brandywine Creek	*1,032
Maps available at: Village Hall, 130 North Main Street, Hudson, Ohio 44236.				
Send comments to: Sheldon Scheweitert, Village Administrator, Village of Hudson, Village Hall, 130 North Main Street, Hudson, Ohio 44236.				
Ohio	(V) Lower Salem, Washington County.	East Fork Duck Creek	At southwest corporate limits	*652
			Just downstream of State Highway 821	*653
			Just downstream of Route T-38	*654
			Approximately 400 feet upstream of Route T-38	*656
			Approximately 1,500 feet upstream of Route T-38	*657
			At northeast corporate limits	*658
Maps available at: The Village Hall, P.O. Box 112, Lower Salem, Ohio.				
Send comments to: The Honorable Robert Holiday, Mayor, Village of Lower Salem, Village Hall, P.O. Box 112, Lower Salem, Ohio 45745.				

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD).
Ohio	(V) Macksburg, Washington County.	Duck Creek	At downstream corporate limit	*676
			Just upstream of Main Street	*676
			Just upstream of Broad Street	*679

Maps available at: Village Hall, P.O. Box 186, Macksburg, Ohio.

Send comments to: The Honorable Dorothy Kemp, Mayor, Village of Macksburg, Village Hall, P.O. Box 186, Macksburg, Ohio 45746.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD).
Ohio	(V) Matamoras, Washington County.	Ohio River	Approximately 2,000 feet downstream of downstream corporate limits.	*631
			Upstream corporate limits	*631

Maps available at: The Village Hall, 1022 Grandview Avenue, New Matamoras, Ohio.

Send comments to: The Honorable John Knowlgon, Mayor, Village of Matamoras, Village Hall, 1022 Grandview Avenue, New Matamoras, Ohio 45767.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD).
Ohio	(C) North Royalton, Cuyahoga County.	East Branch Rocky River	About 50 feet upstream of Bennett Road	*841
			Southern corporate limits at upstream side of Boston Road	*854
			Just downstream of Edgerton Road	*1,140
			Just upstream of Metropolitan Park Drive	*1,150
			Just upstream of Akins Road	*1,161
			About 370 feet upstream of Royalton Road	*1,189
		Baldwin Creek	Northern corporate limits at downstream side of Sprague Road	*876
			About 3,580 feet upstream of Abbey Road	*892
		R17 Tributary	Mouth at East Branch Rocky River	*827
			Just upstream of Edgerton Road	*830
			About 2,350 feet upstream of Edgerton Road	*837

Maps available at: The City Clerk's Office, City Hall, 13834 Ridge Road, North Royalton, Ohio.

Send comments to: Mr. Bissell Marks, Administrative Assistant, City of North Royalton, City Hall, 13834 Ridge Road, North Royalton, Ohio 44133.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD).
Ohio	(V) Spring Valley, Greene County.	Little Miami River	Confluence of Glady Run	*757
			Approximately 475 feet upstream of U.S. Route 42	*757

Maps available at: The Office of Village Clerk, Village Hall, Spring Valley, Ohio.

Send comments to: The Honorable Jack Homer, Jr., Mayor, Village of Spring Valley, 7 West Main, P.O. Box 217, Spring Valley, Ohio 45370.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD).
Ohio	(V) Waynesville, Warren County	Little Miami River	About 3,700 feet downstream State Route 73	*721
			Just upstream State Route 73	*724
		Little Miami River Mill Run Channel.	At confluence with Little Miami River	*724
			About 1,200 feet upstream Corwin Road	*724

Maps available at: Office of Village Clerk, South Main Street, Waynesville, Ohio.

Send comments to: The Honorable Ora Jones, Mayor, Village of Waynesville, 296 South Main Street, P.O. Box 601, Waynesville, Ohio 45068.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD).
Ohio	Woodville (V), Sandusky County	Portage River	Approximately 2,000 feet downstream from corporate limit	*625
			At downstream corporate limit	*627
			Just downstream from U.S. Route 20	*630
			Approximately 3,100 feet upstream from Cherry Street	*633
		Victoria Creek	At confluence with Portage River	*631
			At upstream corporate limit	*633

Maps available at: The Village Hall, 545 Pemberville Road, Woodville, Ohio.

Send comments to: The Honorable Robert Meyer, Mayor, Village of Woodville, Village Hall, 545 Pemberville Road, Woodville, Ohio 43469.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD).
Ohio	(c) Worthington, Franklin County	Olentangy River	Just upstream of southern corporate limit	*745
			Approximately 1,600 feet downstream of State Road 161	*750
			Just downstream of northern corporate limit	*757

Maps available at: City Hall, 789 High Street, Worthington, Ohio 43085.

Send comments to: The Honorable James Lorimer, Mayor, City of Worthington, City Hall, 789 High Street, Worthington, Ohio 43085.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD).
Vermont	(t) Chelsea, Orange County	Jail Brook	Approximately 70 feet upstream of mouth at First Branch White River.	*815
			50 feet downstream of Main Street	*819
		South Washington Brook	Mouth at First Branch White River	*826
			About 800 feet upstream of State Route 110	*838
			Just downstream of dam	*849
			Just upstream of dam	*858
			Approximately 700 feet upstream of dam	*867
			Approximately 2,150 feet upstream of dam	*899
		First Branch White River	At confluence of Jenkins Brook	*790
			Just upstream of Jenkins Brook Road	*799
			Approximately 100 feet upstream of State Route 110	*812
			Just upstream of Maple Street	*820
			At confluence of South Washington Brook	*826
			About 1,700 feet upstream of confluence of South Washington Brook.	*836

Maps available at: Town Clerk's Office, Town Office, Chelsea, Vermont 05038.

Send comments to: Mr. Roger Gilman, First Selectman, Town of Chelsea, Town Office, Chelsea, Vermont 05038.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD).
Vermont	(T) Poultney, Rutland County	Poultney River	About 1,650 feet downstream Granville Street	*402
			About 300 feet downstream Granville Street	*403
			Just upsteam Granville Street	*409
			About 700 feet downstream Delaware and Hudson railway	*410

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			Just downstream Delaware and Hudson railway	*413
			Just upstream Delaware and Hudson railway	*418
			Just upstream South Street	*419
			About 900 feet upstream South Street	*421
			About 150 feet downstream Bridge Street	*426
			About 200 feet upstream Bridge Street	*437
			About 2,200 feet upstream Bridge Street	*438
			About 4,000 feet upstream Bridge Street	*442
Maps available at: Town Office, Poultney, Vermont 05764.				
Send comments to: Mr. Stephen Taran, Chairman, Board of Selectmen, Town Office, Poultney, Vermont 05764.				
Vermont	(V) Poultney, Rutland County	Poultney River	About 1650 feet downstream Granville Street	*402
			About 300 feet downstream Granville Street	*403
			Just upstream Granville Street	*409
			About 700 feet downstream Delaware and Hudson railway	*410
			Just downstream Delaware and Hudson railway	*413
			Just upstream Delaware and Hudson railway	*418
			Just upstream South Street	*419
			About 900 feet upstream South Street	*421
			About 150 feet downstream Bridge Street	*426
			About 200 feet upstream Bridge Street	*437
			About 2200 feet upstream Bridge Street	*438
			About 3100 feet upstream Bridge Street	*440
Maps available at the Town Office, Poultney, Vermont.				
Send comments to Mr. Charles Shenkel, Village Manager, Town Office, Poultney, Vermont 05764.				
Vermont	(T) Stowe, Lamoille County	Little River	Approximately 1,370 feet downstream of Adam's Dam	*624
			Approximately 130 feet upstream of Adam's Dam	*629
			At Wood Product Dam approximately 600 feet downstream of Moscow Road.	*643
			At the River Road Bridge	*664
			At Corporate Limits	*687
		West Branch Little River	At Corporate Limits	*710
			Just upstream State Route 108	*739
			Just upstream Luce Hill Road Bridge	*765
			Just upstream Brook Road	*889
			Just downstream State Route 108, approximately 3,860 feet upstream from Brook Road.	*960
		East Branch Little River	At Corporate Limits	*709
			Just upstream West Hill Road	*712
			Just at East Branch Confluence with Moss Glen Brook	*725
		Sterling Brook	Just upstream Tanzey Road	*735
			Just downstream Moulton Land Bridge	*752
		Moss Glen Brook	Just downstream Stage Coach Road	*725
			Just upstream Stage Coach Road	*729
			Just downstream State Route 100	*741
Maps available at: Town Office, Stowe, Vermont.				
Send comments to Mr. Dale Percey, Chairman, Board of Selectmen, Town Office, Stowe, Vermont 05672.				
Wisconsin	(v) Athens, Marathon County	Black Creek	Eastern Corporate Limits	*1,313
			Confluence of Potato Creek	*1,318
			Just downstream Degner Street	*1,324
			Just upstream Degner Street	*1,327
			About 200 feet upstream Highway 97	*1,340
			About 800 feet upstream Highway 97	*1,348
			About 2,500 feet upstream Highway 97	*1,361
			Northernmost corporate limit	*1,366
		Potato Creek	Confluence with Black Creek	*1,318
			Just downstream Allen Street	*1,321
			Just upstream Allen Street	*1,323
			Southern corporate limit	*1,326
Maps available at Village Clerks Office, Athens, Wisconsin.				
Send comments to Mr. Roy Schafer, Village President, Village of Athens, Village Hall, Athens, Wisconsin 54411.				
Wisconsin	Horicon, Dodge County	Rock River	About 300 feet upstream of County Highway S	*857
			Just upstream of Chicago Milwaukee St. Paul and Pacific Railroad below dam.	*859
			Upstream corporate limits	*861
Maps available at: City Hall, City Clerk's Office, 404 East Lake Street, Horicon, Wisconsin.				
Send comments to: The Honorable Robert G. Sharkey, Mayor, City of Horicon, City Hall, 404 East Lake Street, Horicon, Wisconsin 53032.				
Wisconsin	(v) Hustisford, Dodge County	Rock River	Downstream corporate limits	*849
			Just downstream of dam	*851
			Just upstream of dam	*857
		Lake Sinissippi	Shoreline within Village of Hustisford	*857
Maps available at Village Clerk's Office, Village Hall, Hustisford, Wisconsin.				
Send comments to Mr. Gilvert Falkenthal, Jr., Village President, Village of Hustisford, Village Hall, Hustisford, Wisconsin 53034.				
Wisconsin	Kewaunee County	Kewaunee River	Mouth at Lake Michigan	*584
			Just upstream of County Highway E	*585

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
			Just upstream of the Green Bay and Western Railroad located approximately 1.4 miles downstream of County Highway F.	*589
			Just upstream of County Highway F	*599
			Just downstream of the County Highway C crossing located approximately 1.6 miles upstream of County Highway F.	*610
			Just upstream of County Highway O	*626
			Approximately 4,100 feet upstream of County Highway O	*640
			Just upstream of the County Highway C crossing located approximately 1.9 miles upstream of County Highway O.	*651
			Just upstream of the confluence of Scarboro Creek	*659
			Just upstream of the Ahnapee and Western Railway	*664
			Just upstream of State Highway 54	*668
			Just upstream of the confluence of School Creek	*675
			Just downstream of County Highway A	*680
	Unicorporated Areas of Kewaunee County.	Casco Creek	Mouth at the Kewaunee River	*661
			Just downstream of the Ahnapee and Western Railway	*674
			Just upstream of Rocky Ledge Road	*685
			At the downstream Casco Village limits	*706
			At the upstream Casco Village limits	*719
			Just downstream of the County Highway C crossing located approximately 3,700 feet downstream of County Highway K.	*729
			Just upstream of the County Highway C crossing located approximately 3,700 feet downstream of County Highway K.	*734
			Just upstream of the County Highway C crossing located approximately 2,640 feet downstream of Pheasant Road.	*743
			Just upstream of Pheasant Raod	*745
			Just upstream of County Highway S	*752
			Approximately 3,700 feet upstream of County Highway S	*756
		Silver Creek	At the city of Algoma corporate limits	*593
			Just downstream of dam located approximately 400 feet upstream of Willow Drive.	*612
			Just upstream of dam located approximately 400 feet upstream of Willow Drive.	*623
			Just downstream of the Ahnapee and Western Railway	*636
			Just upstream of the Ahnapee and Western Railway	*644
			Just upstream of County Highway D	*657
			Approximately 1,600 feet upstream of Peachtree Road	*663
		School Creek	Mouth at the Kewaunee River	*675
			Just upstream of State Highway 163	*681
			At the downstream Luxemburg Village limits	*736
			Just upstream of County Highway V	*762
			Just upstream of County Highway H	*771
			Just upstream of Walhain Road	*775
			At upstream county boundary	*776
		Scarboro Creek	Mouth at Kewaunee River	*659
			Just upstream of the Green Bay and Western Railroad	*678
			Just upstream of County Highway A	*693
			Approximately 1.65 miles upstream of County Highway A	*710
		Ahnapee River	Approximately 1,100 feet downstream of the City of Algoma Corporate limits.	*587
			Approximately 1.13 miles upstream of the City of Algoma corporate limits.	*587
		East Twin River	Downstream county boundary	*639
			Just downstream of Nuclear Road	*643
		Lake Michigan	Shoreline	*584
		Green Bay	Shoreline	*585

Maps available at: The Office of the Zoning Administrator, Kewaunee County Courthouse, Kewaunee, Wisconsin.
Send comments to: Mr. Donald Quistorff, County Board Chairman, Kewaunee County Courthouse, Kewaunee, Wisconsin 54216.

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
Wisconsin	(C) Madison, Dane County	Yahara River	Lake Waubesa	*847
			Lake Monona	*848
			Lake Mendota	*852
			Just upstream of State Highway 113	*854
		Nine Springs Creek	Mouth at Yahara River	*848
			Just upstream of Moorland Road	*849
			Just upstream of County Highway MM	*852
			Upstream corporate limits located approximately 765 feet upstream of Syene Road.	*854
		East Branch Starkweather Creek	Confluence with West Branch Starkweather Creek	*850
			Just upstream of State Highway 30	*851
			Just upstream of Sycamore Avenue	*852
			Upstream corporate limits	*853
		Starkweather Creek and West Branch Starkweather Creek.	Mouth at Lake Monona	*848
			Just downstream of Fair Oaks Avenue	*851
			Just upstream of Washington Avenue	*854
			Just upstream of State Highway 30	*855
			Just upstream of International Lane	*858
			Upstream corporate limits located 2,640 feet upstream of U.S. Highway 51.	*860

Proposed Base (100-Year) Flood Elevations—Continued

State	City/town/county	Source of flooding	Location	#Depth in feet above ground. *Elevation in feet (NGVD)
		Unnamed Tributary to Lake Waubesa.	Downstream corporate limits	*850
			Just upstream of Dutch Mill Road	*853
			Just downstream of Marsh Road	*858
		Murphy Creek	Between Lake Monona and Lake Wingra	*848
Maps available at: Planning and Development Division, City-County Building, Room 414, Madison, Wisconsin.				
Send comments to: Charles Dinauer, Planning and Development Division, City of Madison, City-County Building, Room 414, Madison, Wisconsin 53708.				
Wisconsin	(c) Omro, Winnebago County	Fox River	Downstream corporate limits	*751
			Upstream corporate limits	*753
Maps available at: City Clerk's Office, City Hall, 205 South Webster Avenue, Omro, Wisconsin.				
Send comments to: The Honorable Edwin Sheppard, Mayor, City of Omro, City Hall, 205 South Webster Avenue, Omro, Wisconsin 54963.				
Wisconsin	(V) Theresa, Dodge County	East Branch Rock River	At the downstream corporate limits	*932
			Just upstream of Milwaukee Street	*935
			At the upstream corporate limits	*936
Maps available at: The Village Clerk's Office, Village Hall, 201 South Milwaukee, Theresa, Wisconsin.				
Send comments to: Mr. Gordon Neitzel, Village President, Village of Theresa, Village Hall, 201 South Milwaukee, Theresa, Wisconsin 53091.				
Wisconsin	(C) Verona, Dane County	Badger Mill Creek	Approximately 3,400 feet downstream of Main Street	*937
			Approximately 2,300 feet downstream of Main Street	*942
			Just upstream of Unnamed Road	*944
			Just upstream of Main Street	*945
			Approximately 4,600 feet upstream of Main Street	*950
		Dry Tributary to Badger Mill Creek	Just upstream of Chicago and North Western Railroad	*945
			Approximately 1,150 feet upstream of Chicago and North Western Railroad.	*946
			Approximately 1,400 feet upstream of Chicago and North Western Railroad.	*947
Maps available at: The City Administrator's Office, City Hall, Verona, Wisconsin.				
Send comments to: The Honorable Richard Brown, Mayor, City of Verona, City Hall, P.O. Box 188, Verona, Wisconsin 53593.				
Wisconsin	(V) Winneconne; Winnebago County.	Wolf River	Entire Shoreline	*750
Maps available at: Village Clerk's Office, Village Hall, 224 West Main Street, Winneconne, Wisconsin 54986.				
Send comments to: Mr. James P. Coughlin, Village President, Village of Winneconne, Village Hall, 224 West Main Street, Winneconne, Wisconsin 54986.				

(National Flood Insurance Act of 1968 (Title XIII of Housing and Urban Development Act of 1968), effective January 28, 1969 (33 FR 17804, November 28, 1968), as amended (42 U.S.C. 4001–4128); Executive Order 12127, 44 FR 19867; and delegation of authority to Federal Insurance Administrator 44 FR 20963.)

Issued: September 17, 1979.

Gloria M. Jimenez,

Federal Insurance Administrator.

[FR Doc. 79-30561 Filed 10-4-79; 8:45 am]

BILLING CODE 6718-03-M

Notices

Federal Register
Vol. 44, No. 195
Friday, October 5, 1979

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

Contagious Equine Metritis (CEM); Meeting

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Notice of public meeting.

SUMMARY: The purpose of this document is to give notice of an informal public meeting concerning the interstate and international movement of horses and other equidae relating to contagious equine metritis (CEM).

PLACE, DATE AND TIME OF MEETING: Room 4306, South Building, Department of Agriculture, 14th Street and Independence Avenue, SW, Washington, D.C., November 8, 1979, at 1:30 to 4:30 p.m..

SUPPLEMENTAL INFORMATION: This meeting is sponsored by the Department of Agriculture for the purpose of exchanging views and information relating to the interstate movement of equidae from areas quarantined and the importation of certain horses and other equidae from countries infected with CEM. An APHIS representative will serve as chairman at this informal public meeting, and an agenda will be prepared to outline background information. Certain presentations by Agency personnel will be scheduled at this meeting to provide resource information.

This meeting is open to the public. Written statements concerning this matter may be filed with the Department of Agriculture on or before November 8, 1979.

All written submissions made pursuant to this notice will be made available for public inspection at the Federal Building, 6505 Belcrest Road, Room 739, Hyattsville, MD, during regular hours of business (8 a.m. to 4:30 p.m., Monday to Friday, except holidays) in a manner convenient to the public business (7 CFR 1.27(b)).

Further information may be obtained from and written statements may be submitted to Dr. R. C. Knowles, Chief Staff Veterinarian, Sheep, Goat, Equine, and Ectoparasites Staff, Veterinary Services, APHIS, USDA, Room 739, Federal Building, Hyattsville, MD 20782, 301-436-8434.

Dated: September 27, 1979.

E. A. Schilf,

Acting Deputy Administrator, Veterinary Services.

[FR Doc. 79-30625 Filed 10-4-79; 8:45 am]

BILLING CODE 3410-34-M

CIVIL AERONAUTICS BOARD

Applications for Certificates of Public Convenience and Necessity and Foreign Air Carrier Permits Filed Under Subpart Q of the Board's Procedural Regulations

Notice is hereby given that, during the week ended September 28, 1979 CAB has received the applications listed below, which request the issuance, amendment, or renewal of certificates of public convenience and necessity or foreign air carrier permits under Subpart Q of 14 CFR 302.

Answers to foreign permit applications are due 28 days after the application is filed. Answers to certificate applications requesting restriction removal are due within 14 days of the filing of the application. Answers to conforming applications in a restriction removal proceeding are due 28 days after the filing of the original application. Answers to certificate applications (other than restriction removals) are due 28 days after the filing of the application. Answers to conforming applications or those filed in conjunction with a motion to modify scope are due within 42 days after the original application was filed. If you are in doubt as to the type of application which has been filed, contact the applicant, the Bureau of Pricing and Domestic Aviation (in interstate and overseas cases) or the Bureau of International Aviation (in foreign air transportation cases).

Subpart Q Applications

Date filed	Docket No.	Description
Sept. 24, 1979	36672	Sky West Aviation, Inc., c/o Harry A. Bowen, 234 Georgetown Building 2233 Wisconsin Avenue, N.W., Washington, D.C. 20007. Application of Sky West Aviation, Inc. requesting the Board pursuant to Section 401 of the Act and Part 201 of the Board's Economic Regulations for amendment of its certificate of public convenience and necessity by adding the intermediate point Flagstaff, Arizona between the terminal point Salt Lake City, Utah and the terminal point Phoenix, Arizona. Conforming Applications and Answers due on October 22, 1979.
Sept. 24, 1979	36675	Texas International Airlines, Inc., P.O. Box 12788, Houston, Texas 77017. Application of Texas International Airlines, Inc. requesting the Board pursuant to Section 401(e)(7)(B) of the Act, Rule 1701(b) of Subpart Q of the Board's Rules of Practice for an amendment of its certificate of public convenience and necessity for Route 82 so as to eliminate Condition (5) of such certificate therein, viz: "(5) If the holder has scheduled two daily round trips at each intermediate point, it may omit that point or any additional trips scheduled over all or part of this route as long as it remains in compliance with all other conditions in this certificate: *Provided, however,* that, if the holder has scheduled one daily round trip to El Paso, Texas, or Salt Lake City, Utah, or one round trip five days per week plus one round trip during the weekend period to Memphis, Tennessee, it may omit that point on any additional trips." Conforming Applications and Answers are due on October 9, 1979.
Sept. 24, 1979	36681	Capitol International Airways, Inc., P.O. Box 325, Smyrna, Tennessee 37167. Application of Capitol International Airways, Inc. requesting the Board pursuant to Section 401 of the Act for the issuance or amendment of its certificate of public convenience and necessity authorizing it to engage in air transportation of persons, property, and mail between: The coterminal points San Francisco, Oakland and San Jose, Calif., the intermediate point Las Vegas, Nev. and the coterminal points New York, N.Y. and Newark, N.J. Conforming Applications and Answers are due on October 22, 1979.
Sept. 26, 1979	36716	Pan American World Airways, Inc., Pan Am Building, New York, New York 10017. Application of Pan American World Airways, Inc. requests the Board pursuant to Section 401 of the Act and Subpart Q of the Board's Procedural Regulations for the issuance of a certificate of public convenience and necessity authorizing it to engage in foreign air transportation of persons, property, and mail over the following route: Between the coterminal points Boston, Mass.; New York/Newark, N.J.; Baltimore, Md.; Washington, D.C.; Miami and Tampa, Fla.; San Juan, P.R.; New Orleans, La.; Houston, Tex.; Chicago, Ill.; Detroit, Mich.; Los Angeles/Long Beach/Ontario and San

Subpart Q Applications—Continued

Date filed	Docket No.	Description
		Francisco/Oakland, Calif.; Seattle, Wash.; and Honolulu, Hawaii, and the coterminal points Mexico City, Mexico; Guatemala City, Guatemala; San Jose, Costa Rica; Panama City, Panama; Medellin, Cartegena, Cali and Bogota, Colombia; Caracas, Venezuela; Quito and Guayaquil, Ecuador; Lima, Peru; La Paz, Bolivia; Santiago, Chile; Asuncion, Paraguay; Rio De Janiero, Brazil; Montivedeo, Uruguay, and Buenos Aires, Argentina. Pan American requests that its application be set for oral evidentiary hearing pursuant to Rule 1750(a)(1) of the Board's Rules of Practice. Conforming Applications and Answers are due on October 24, 1979.

Phyllis T. Kaylor,
Secretary.

[FR Doc. 79-30948 Filed 10-4-79; 8:45 am]

BILLING CODE 6320-01-M

CF Air Freight, Inc.; Application for an All-Cargo Air Service Certificate

September 28, 1979.

In accordance with Part 291 (14 CFR 291) of the Board's Economic Regulations (effective November 8, 1978), notice is hereby given that the Civil Aeronautics Board has received an application, Docket 36365, from CF Air Freight, Inc., 3055 Clearview Way, San Mateo, California 94402, for an all-cargo air service certificate to provide domestic cargo transportation.

Under the provisions of section 291.12(c) of Part 291, interested persons may file an answer in opposition to this application within twenty-one (21) days after publication of this notice in the Federal Register. An executed original and six copies of such answer shall be addressed to the Docket Section, Civil Aeronautics Board, Washington, D.C. 20428. It shall set forth in detail the reasons for the position taken and must relate to the fitness, willingness, or ability of the applicant to provide all-cargo air service or to comply with the Act or the Board's orders and regulations. The answer shall be served upon the applicant and state the date of such service.

Phyllis T. Kaylor,
Secretary.

[FR Doc. 79-30950 Filed 10-4-79; 8:45 am]

BILLING CODE 6320-01-M

PBA Airlines, Inc.; Application for an All-Cargo Air Service Certificate

September 28, 1979.

In accordance with Part 291 (14 CFR 291) of the Board's Economic Regulations (effective November 8, 1978), notice is hereby given that the Civil Aeronautics Board has received an application, Docket 36553, from PBA Airlines, Inc., 2814 New Spring Road, Atlanta, Georgia 30339 for an all-cargo air service certificate to provide domestic cargo transportation.

Under the provisions of section 291.12(c) of Part 291, interested persons may file an answer in opposition to this application on or before October 26, 1979. An executed original and six copies of such answer shall be addressed to the Docket Section, Civil Aeronautics Board, Washington, D.C. 20428. It shall set forth in detail the reasons for the position taken and must relate to the fitness, willingness, or ability of the applicant to provide all-cargo air service or to comply with the Act or the Board's orders and regulations. The answer shall be served upon the applicant and state the date of such service.

Phyllis T. Kaylor,
Secretary.

[FR Doc. 79-30949 Filed 10-4-79; 8:45 am]

BILLING CODE 6320-01-M

[Order 79-10-6; Docket 36766]

American Airlines and Continental Airlines et al., Nonstop Air Route Authority; Costa Rica

AGENCY: Civil Aeronautics Board.

ACTION: Notice of Order 79-10-6, United States-Costa Rica Show Cause Proceeding, Docket 36766.

SUMMARY: The Board is proposing to award nonstop air route authority between Costa Rica and any point in the United States other than Miami and New Orleans under section 401 of the Federal Aviation Act of 1958, as amended, to American Airlines and Continental Airlines, and any other fit, willing and able applicant whose fitness can be established by officially noticeable data. The complete text of this order is available as noted below.

DATES: Objections: All interested persons having objections to the Board issuing the proposed authority shall file, and serve upon all persons listed below, no later than November 5, 1979, a statement of objections, together with a summary of testimony, statistical data, and other material expected to be relied upon to support the stated objections.

Additional Data: All existing and would-be applicants who have not filed (a) illustrative service proposals, (b) environmental evaluations, and (c) an estimate of fuel to be consumed in the first year are directed to do so no later than October 24, 1979.

ADDRESSES: Objections or Additional Data should be filed in Docket 36766, Docket Section, Civil Aeronautics Board, Washington, D.C. 20428.

FOR FURTHER INFORMATION CONTACT: Peter Rosenow, Bureau of International Aviation, Civil Aeronautics Board, 1825 Connecticut Avenue NW., Washington, D.C. 20428 (202) 673-5035.

SUPPLEMENTARY INFORMATION: The Board is proposing to grant (1) Continental new air route authority between the coterminal points Los Angeles, Calif., and Houston, Tex., and a terminal point or points in Costa Rica, and (2) American new air route authority between the coterminal points Los Angeles and San Francisco, Calif., Chicago, Ill., Dallas/Ft. Worth and Houston, Tex., New York, N.Y., Newark, N.J., Baltimore, Md., Washington, D.C., and San Juan, P.R., and a terminal point or points in Costa Rica. American and Continental may carry local traffic between and among U.S. coterminal points on flights serving Costa Rica. Objections should be served on the following: Air Florida, American Airlines, Continental Airlines, Eastern Airlines, Evergreen International Airlines, Red Carpet Flying Service, Republic Airlines, Trans-Americas Airlines, Trans International Airlines, the Houston Parties, the Miami Parties, the Ambassador of Costa Rica in Washington, D.C., and the Departments of State and Transportation.

The complete text of Order 79-10-6 is available from the Distribution Section, Room 516, Civil Aeronautics Board, 1825 Connecticut Avenue NW., Washington, D.C. 20428. Persons outside the metropolitan area may send a postcard request for Order 79-10-6 to that address.

By the Civil Aeronautics Board: October 2, 1979.

Phyllis T. Kaylor,
Secretary.

[FR Doc. 79-30951 Filed 10-4-79; 8:45 am]

BILLING CODE 6320-01-M

DEPARTMENT OF COMMERCE

Bureau of the Census

Census Advisory Committee on the Asian and Pacific Americans Population for the 1980 Census; Public Meeting

Pursuant to the Federal Advisory Committee Act (Pub. L. 94-463), as amended, notice is hereby given that the Census Advisory Committee on the Asian and Pacific Americans Population for the 1980 Census will convene on October 26, 1979, at 9:15 a.m. The Committee will meet in Room 2424, Federal Building 3, at the Bureau of the Census in Suitland, Maryland.

This Committee was established in June 1976 to advise the Director, Bureau of the Census, during the planning of the 1980 Census of Population and Housing on such elements as improving the accuracy of the population count, developing definitions and terminology for improved identification and classification of the Asian and Pacific Americans population, suggesting areas of research, recommending subject content and tabulations of particular use to the Asian and Pacific Americans population, and expanding the dissemination of census results among present and potential users of census data in the Asian and Pacific Americans community.

The Committee is composed of 21 members appointed by the Secretary of Commerce, and consititutes a broad spectrum of community leaders, scholars, and other appropriate persons.

The agenda for the meeting, which is scheduled to adjourn at 4:30 p.m., is: (1) Introductory remards by the Director, Bureau of the Census; (2) current status of 1980 census planning; (3) publication plans; (4) recruiting enumerators—citizenship requirement, and high-crime areas; (5) Affirmative Action Program; (6) Committee discussion; and (7) Committee recommendations and plans for the next meeting.

The meeting will be open to the public, and a brief period will be set aside for public comment and questions. Extensive questions or statements must be submitted in writing to the Committee Control Officer at least 3 days prior to the meeting.

Persons planning to attend and wishing additional information concerning this meeting should contact the Committee Control Officer, Mr. Clifton S. Jordan, Deputy Chief, Decennial Census Division, Bureau of the Census, Room 3779, Federal Building 3, Suitland, Maryland. (Mailing address: Washington, D.C. 20233). Telephone: (301) 763-5169.

Dated: October 2, 1979.

Vincent P. Barabba,

Director, Bureau of the Census.

[FR Doc. 79-31063 Filed 10-4-79; 8:45 am]

BILLING CODE 3510-07-M

National Bureau of Standards

Establishment and Membership of Limited Performance Review Board

This notice announces the establishment by the Director of the National Bureau of Standards (NBS), as Appointing Authority for the Senior Executive Service at NBS, of the Limited Performance Review Board (LPRB) and of the appointment of two of its initial members. The appointment of the third person to complete the initial membership of the LPRB, will be announced in the **Federal Register** at such time as the appointment is made.

The purpose of the LPRB is to review performance agreements, performance appraisals and ratings, recommendations for certain personnel actions and other related material, and to make recommendations to the Appointing Authority concerning such matters in such a manner as will assure the fair and equitable treatment of senior executives and the organizations of which they are members and instill in the minds of such senior executives confidence in the integrity, competence, and impartiality of the LPRB. The LPRB will perform its review functions for all NBS senior executives who are members of the NBS Executive Board (except the NBS Deputy Director) and those senior executives who are members of the NBS General Performance Review Board (GPRB).

Notices regarding the establishment of the NBS GPRB, its purpose and its membership, were announced in the **Federal Register** on September 12, 1979 (44 FR 53098) and September 25, 1979 (44 FR 55222).

The names, titles and terms of the two members of the LPRB who have been appointed are set out below.

Dr. Edward L. Brady, Chairman, Associate Director for International Affairs, National Bureau of Standards, Washington, D.C. 20234, Term—3 years.

Dr. Arnold W. Pratt, Director, Computer Research and Technology Division, National Institutes of Health, Bethesda, Maryland 20014, Term—2 years.

Persons desiring any further information about the LPRB or its membership may contact Mr. Clarence Hardy, Chief, Personnel Division, National Bureau of Standards, Washington, D.C. 20234 (301) 921-3555.

Dated: October 3, 1979.

Thomas A. Dillon,

Acting Director.

[FR Doc. 79-31079 Filed 10-4-79; 8:45 am]

BILLING CODE 3510-03-M

COMMITTEE FOR PURCHASE FROM THE BLIND AND OTHER SEVERELY HANDICAPPED

Procurement List 1979; Additions

AGENCY: Committee for Purchase from the Blind and Other Severely Handicapped.

ACTION: Additions to Procurement List.

SUMMARY: This action adds to Procurement List 1979 commodities to be produced by workshops for the blind or other severely handicapped.

EFFECTIVE DATE: October 5, 1979.

ADDRESS: Committee for Purchase from the Blind and Other Severely Handicapped, 2009 14th Street North, Suite 610, Arlington, Virginia 22201.

FOR FURTHER INFORMATION CONTACT: C. W. Fletcher, (703) 557-1145.

SUPPLEMENTARY INFORMATION: On April 16, 1979 and July 27, 1979 the Committee for Purchase from the Blind and Other Severely Handicapped published notices (44 FR 22503 and 44 FR 44206) of proposed additions to Procurement List 1979, November 15, 1978 (43 FR 53151).

After consideration of the relevant matter presented, the Committee has determined that the commodities listed below are suitable for procurement by the Federal Government under 41 U.S.C. 46-48c, 85 Stat. 77.

Accordingly, the following commodities are hereby added to Procurement List 1979:

Class 6230

Light, Marker, Distress
6230-00-892-5192

Class 5510

Stake, Wood
5510-00-NSH-0001
Requirements for the Bureau of Land Management, Department of the Interior at the following Oregon locations only: Roseburg, Medford, Coos Bay, Eugene and Salem.

C. W. Fletcher,

Executive Director.

[FR Doc. 79-30958 Filed 10-4-79; 8:45 am]

BILLING CODE 6820-33-M

Procurement List 1979; Deletion

AGENCY: Committee for Purchase from the Blind and Other Severely Handicapped.

ACTION: Deletion from Procurement List.

SUMMARY: This action deletes from Procurement List 1979 a service provided by workshops for the blind or other severely handicapped.

EFFECTIVE DATE: October 5, 1979.

ADDRESS: Committee for Purchase from the Blind and Other Severely Handicapped, 2009 14th Street North, Suite 610, Arlington, Virginia 22201.

FOR FURTHER INFORMATION CONTACT: C. W. Fletcher, (703) 557-1145.

SUPPLEMENTARY INFORMATION: On August 10, 1979 the Committee for Purchase from the Blind and Other Severely Handicapped published a notice (44 FR 47134) of proposed deletion from Procurement List 1979, November 15, 1978 (43 FR 53151).

After consideration of the relevant matter presented, the Committee has determined that the service listed below is no longer suitable for procurement by the Federal Government under 41 U.S.C. 46-48c, 85 Stat. 77.

Accordingly, the following service is hereby deleted from Procurement List 1979:

SIC 7641

Furniture Rehabilitation
Long Beach, California plus 100-mile radius, excluding San Diego County and San Clemente

C. W. Fletcher,
Executive Director.

[FR Doc. 79-30959 Filed 10-4-79; 8:45 am]
BILLING CODE 6820-33-M

Privacy Act of 1974; Systems of Records, Annual Publication

The Privacy Act of 1974 (5 U.S.C. 552a (e)(4)) requires agencies to publish annually in the Federal Register a notice of the existence and character of their systems of records. The Committee for Purchase from the Blind and Other Severely Handicapped last published the full text of its systems of records at 42 F.R. 48075, August 15, 1977. No further changes have occurred, therefore, the systems of records remain in effect as published.

The full text of the Committee for Purchase from the Blind and Other Severely Handicapped systems of records also appears in Privacy Act Issuances, 1978 Compilation, Volume III, page 732. This volume may be ordered through the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402. The price of this volume is $10.25.

C. W. Fletcher,
Executive Director.

[FR Doc. 79-30960 Filed 10-4-79; 8:45 am]
BILLING CODE 6820-33-M

DEPARTMENT OF DEFENSE

Department of the Army

U.S. Army Medical Research and Development Advisory Panel Ad Hoc Study Group on Medicinal Chemistry; Partially Closed Meeting

In accordance with Section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92-463), announcement is made of the following Committee meeting:

Name of committee: United States Army Medical Research and Development Advisory Panel Ad Hoc Study Group on Medicinal Chemistry.

Date of meeting: October 26, 1979.

Time and place: 0845 hours, Walter Reed Army Medical Center, Room 3092, Building 40, Washington, DC 20012.

Proposed agenda: This meeting will be open to the public on October 26, 1979, from 0845-1150 to discuss the scientific research program of the Medicinal Chemistry Branch, Walter Reed Army Institute of Research. Attendance by the public at open sessions will be limited to space available.

In accordance with the provisions set forth in Section 552b(c)(6), Title 5, U.S. Code and Section 10(d) of Pub. L. 92-463, the meeting will be closed to the public on October 26, 1979, from 1300-1630 for the review, discussion and evaluation of individual programs and projects conducted by the U.S. Army Medical Research and Development Command, including consideration of personnel qualifications and performance, the competence of individual investigators, medical files of individual research subjects, and similar items, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Dr. Howard Noyes, Associate Director, Walter Reed Army Institute of Research, Building 40, Room 1111, Walter Reed Army Medical Center, Washington, DC 20012 (202/576-3061) will furnish summary minutes, roster of Committee members, and substantive program information.

For the Commander.

LeeRoy G. Jones,
Colonel, MC, Deputy Commander.

[FR Doc. 79-30846 Filed 10-4-79; 8:45 am]
BILLING CODE 3710-08-M

Corps of Engineers

Draft Environmental Impact Statement (DEIS) for the Kikiaola Harbor Project, Island of Kauai, Hawaii; Intent

September 25, 1979.

AGENCY: US Army Corps of Engineers, DoD Honolulu District.

ACTION: Notice of Intent to Prepare a DEIS.

SUMMARY: 1. The proposed action is a harbor improvement project, the major objectives of which are to reduce navigational hazard to the entrance channel, provide adequate berthing spaces, reduce surge within the harbor basin and to minimize siltation in the entrance channel and harbor basin.

2. Preliminary alternative plans are based on input from the public as well as oceanographic information obtained from computer wave refraction analysis, theoretical wave diffraction analysis, an underwater reconnaissance investigation and subsurface borings. The plan, authorized in the 1967 US Army Corps of Engineers survey report, is one of three alternatives under consideration. This alternative entails removal of a portion of the existing east stub breakwater which extends into the proposed entrance channel, raising the crest elevation of the east breakwater, constructing a 270-foot wave absorber, and dredging a 12-foot deep, 120-foot wide entrance channel. Alternative No. 2 was developed to minimize siltation in the entrance channel and reduce surge and wave heights in the harbor basin. This plan includes new inner and outer stub breakwaters, turning basin, and access channel. Alternative No. 3 is similar to Alternative No. 2 in most of the improvement features. By locating the turning basin between the west and inner breakwaters, Plan No. 3 maximizes the berthing capacity which is limited by the present harbor configuration.

3. The program involves coordination with the sponsoring agencies, other government agencies, community organizations and the general public. Activities include informal meetings, workshops, formal public meetings, issuance of public notices and letter responses. All pertinent agencies have been notified of study initiation. An initial public meeting was held with interested agencies and the public on 20 February 1979. Additional workshop and public meetings are scheduled in November 1979 and May 1980, respectively.

a. *Significant Issues to be Analyzed:*

(1) Comparative environmental impacts of the proposed alternatives.

(2) Project impacts on cultural resources.

(3) Project impacts on water quality.

(4) Project impacts on marine resources.

(5) Assessment of community responses to alternative plans.

b. *Possible Assignments for Input into the EIS among the Lead and Cooperating Agencies:*

(1) *US Fish and Wildlife Service.* Provision of a Fish and Wildlife Coordination Act Section 2b report to assist in assessment of ecological impacts.

(2) *State Historic Preservation Officer.* Identification and evaluation of previous cultural resource surveys.

(3) *State Department of Transportation.* Socio-economic data.

(4) *State Department of Health.* Water Quality data and Section 404 certification.

c. *Identification of Other Environmental Review and Consultation Requirements:*

(1) Section 106 of the National Historic Preservation Act of 1966 requires survey and coordination regarding potential impact on significant cultural resources.

(2) Section 404 of the Clean Water Act of 1977 requires evaluation of projects to assess impacts resulting from deposition of dredged or fill materials into waters of the U.S.

(3) Coastal Zone Management Act of 1972 requires that a project must comply with the federal law as well as be consistent with the Coastal Zone Management program for the State of Hawaii.

4. Because the study was initiated last year, a scoping meeting will not be held on the project. Significant agencies involved in the planning process are already informed of the proposed action. Those agencies include the sponsoring agency, State of Hawaii Department of Transportation, State Historic Preservation Officer and the US Fish and Wildlife Service.

5. Under the present schedule, the DEIS will be made available to the public in May 1980.

Address: Questions about the proposed action and DEIS can be answered by: Mr. James Hatashima, Project Engineer, US Army Engineer District, Honolulu, Building 230, Fort Shafter, Hawaii 96858, Telephone: (808) 438-1907.

Dated: September 25, 1979.

B. R. Schlapak,

Lt. Col., Corps of Engineers, District Engineer.

[FR. Doc. 79-31006 Filed 10-4-79; 8:45 am]

BILLING CODE 3710-NN-M

Corps of Engineers

[80-03/2]

Intent To Prepare a Draft Environmental Impact Statement (DEIS) for the Proposed Atlantic Coast of Maryland and Assateague Island, Virginia Study

AGENCY: U.S. Army Corps of Engineers, DOD.

ACTION: Notice of Intent to Prepare a Draft Environmental Impact Statement (DEIS).

SUMMARY: 1. The proposed plans for providing beach erosion control consists of raising and widening the beach from around 10th Street in the town of Ocean City, north to the Maryland/Delaware line. This would be accomplished by hydraulically dredging material from an acceptable borrow area(s) and depositing this material on shore. The length of the project is approximately 8.9 miles and the maximum beach width studied is 190 feet. To provide for hurricane protection, a steel sheet pile bulkhead will be constructed on the beachside of the boardwalk from 7th Street to the north end of the boardwalk. From that point to the Maryland/Delaware border, a dune line will be created.

For Assateague Island, those areas identified by the National Park Service requiring erosion control and hurricane protection were investigated and engineering plans developed. Plans of protection consist of beach fill and dune creation. The National Park Service may seek authorization to construct the plans for Assateague Island, if they so desire, and accordingly, this portion of the project will not be considered by the Environmental Statement.

2. The alternatives include varying beach widths, and dune/bulkhead heights depending on the degree of storm protection desired. Other alternatives being investigated include such protective measures as groin systems and offshore breakwaters.

3.a. The study was authorized in June 1963, and begun in 1965. Public meetings were held on 15 April 1964 and 11 November 1971. These meetings were conducted in order to afford interested parties an opportunity to express their views on the investigation or plans being considered. The lack of non-Federal support in 1972 deferred study progress until 1978 when renewed non-Federal interest resulted in resumption of the study. A coordination meeting involving state, local and Federal agencies was held on 8 December 1978 for the purpose of obtaining views. Local, State, and Federal agencies expressed and coordinated their interests in the planning process through written correspondence.

3.b. The significant issues to be addressed in the DEIS are (1) the selection of borrow areas which are least damaging to the natural resources, and (2) the selection of the plan which is the most appropriate with respect to the natural environment and the economy of the area.

4. Due to the familiarity of the project by local and Federal agencies, and the coordination that has taken place to date, not additional scoping meeting other than the one described in paragraph "3a" above will be held.

5. The DEIS will be available to the public in April 1980.

ADDRESS: Questions about the proposed action and DEIS can be answered by Mr. Charles Yoe, Study Manager Baltimore District, Corps of Engineers, P.O. Box 1715, Baltimore, Maryland 21203, Telephone (301) 962-2530.

James W. Peck,

Colonel, Corps of Engineers, District Engineer.

[FR Doc. 79-31005 Filed 10-4-79; 8:45 am]

BILLING CODE 3710-41-M

DEPARTMENT OF ENERGY

Voluntary Agreement and Plan of Action To Implement the International Energy Program; Meeting

In accordance with Section 252(c)(1)(A)(i) of the Energy Policy and Conservation Act (42 U.S.C. 6201 *et seq.*) notice is hereby provided that a meeting of the Industry Working Party (IWP) to the International Energy Agency (IEA) will be held on October 15, 1979, at the offices of the IEA, 2 rue Andre Pascal, Paris, France, beginning at 9:30 a.m.

The agenda for the meeting is under the control of the Standing Group on the Oil Market (SOM) *ad hoc* group. It is expected that the IWP representatives will be asked to discuss the following subject:

Further questions on the registration of oil market transactions.

As provided in Section 252(c)(1)(A)(ii) of the Energy Policy and Conservation Act, this meeting will not be open to the public.

Issued in Washington, D.C., October 1, 1979.

Craig S. Bamberger,

Acting Assistant General Counsel, International Trade & Emergency Preparedness.

[FR Doc. 79-30956 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

Bonneville Power Administration

Allocation of Firm Electric Energy and System Reserve Energy Notice of Intent To Prepare a Draft Environmental Impact Statement

AGENCY: Bonneville Power Administration, Department of Energy.

ACTION: Notice of Intent to Prepare a Draft Environmental Impact Statement.

SUMMARY: Bonneville Power Administration (BPA) issued a Notice of Insufficiency on June 24, 1976, to inform its preference customers that BPA would not meet their firm energy load growth after July 1, 1983, except for those utilities whose loads do not exceed a guaranteed minimum allocation. Allocation formulas incorporated in the existing contracts determine allocations of firm energy for the duration of each contract. However, no method exists to guide (a) reallocation of the firm energy which will become available as existing firm power sales contracts expire between 1981-1994, or (b) allocation of firm energy which will become available to the Federal Columbia River Power System (FCRPS) from new resources, irrespective of source. Consequently, BPA must develop an allocation policy as soon as possible since it will affect regional well-being, utility resource plans and conservation efforts.

1. *Description of the Proposed Action:* BPA proposes to offer existing preference customers and preference applicants power sales contracts with allocation provisions which would be effective July 1, 1983 or later for contracts executed after that date. All contracts will terminate July 1, 2001. All allocations made in accordance with these provisions would be effective for the periods specified in the contracts.

Proposed changes from current BPA policy include:

(a) Making Federal energy available only to preference applicants, as well as existing preference customers;

(b) Establishing a conservation reserve (15 percent of the total firm energy available for allocation to preference customers);

(c) Requiring each customer, as a condition for eligibility for a full allocation of firm energy, to establish a conservation program/implementation plan;

(d) Terminating the base allocation to all customers and the 25 MW minimum allocation to existing preference customers on July 1, 1991;

(e) Discontinuing direct firm energy sales to current Federal agency and direct-service industrial (DSI or DSIs) customers upon expiration of existing power sales contracts;

(f) Selling system reserve energy to preference customers as a separate class of power; and

(g) Establishing an arrangement to assure that the sharing of benefits and costs among BPA customers will more closely approximate what will occur after July 1, 1991, when all customers will receive pro rata allocations based on their net firm energy requirements.

2. *Reasonable Alternatives:* BPA developed six alternative allocation policies which incorporate varying approaches to a common set of issues. In the course of testing both their technical feasibility and potential impacts, the alternatives and associated methods of allocation have undergone modification. The issues included (1) the class(es) of BPA customer(s) to be served (i.e., current preference customers, new preference customers, Pacific Northwest investor-owned utilities (IOU or IOUs), Federal agencies, and DSIs); (2) the extent to which BPA should require customers to commit their assured resources to meet their own load requirements before BPA determines their allocation; (3) the types of loads to be served (i.e., the end uses of the firm energy; BPA wholesales to its utility customers who, in turn, sell it, at retail, to consumers); (4) the determination of load requirements and the amount of energy expected to be available to help meet those loads; (5) the use of system energy reserves; (6) the term of contract and duration of the allocations; (7) minimum allocations to preference customers; (8) grades of power; (9) rates for firm energy and (10) conservation.

3. *Scoping.* BPA will hold eight Public Information Forums to explain the proposal, present the general findings of its supporting analyses, invite suggestions regarding the scope of the EIS, and answer questions on the proposal and alternatives. The forums will take place October 31, and during the first week of November 1979. The October 31 meeting in Portland will be more technical in nature. A proposed outline of the draft EIS will be distributed and a short presentation on environmental considerations given. These meetings will be held at the following locations and times:

October 31, BPA Auditorium, 1002 NE. Holladay Street, Portland, Oregon, 9 a.m.

November 5, Mt. Hood Room, Travelodge at the Coliseum, 1441 NE. Second Avenue, Portland, Oregon, 7:30 p.m.

November 5, The Forum, Walla Walla Community College, 500 Tausick Way, Walla Walla, Washington, 7:30 p.m.

November 6, Forum R, Eugene Hotel, 222 East Broadway, Eugene, Oregon, 7:30 p.m.

November 6, City Council Chambers, 140 South Capitol, Idaho Falls, Idaho, 7:30 p.m.

November 7, Terrace Room A, Ridpath Hotel, West 515 Sprague, Spokane, Washington, 7:30 p.m.

November 7, Phoenix C and D Rooms, Hyatt House-Seattle, Sea-Tac International Airport, 17001 Pacific Highway South, Seattle, Washington, 7:30 p.m.

November 8, Colt 44 and Colt 45 Rooms, Outlaw Inn, 1701 Highway 93 South, Kalispell, Montana, 7:30 p.m.

On Monday, December 3, 1979, a scoping meeting to identify and discuss the substantive environmental issues to be addressed in the EIS will be held at BPA headquarters building, Room 464, 1002 NE. Holladay Street, Portland, Oregon 97208, commencing at 9 a.m. BPA recommends attendance at one of the Public Information Forums to facilitate understanding of the allocation proposal and related environmental issues. However, a brief discussion of the proposal will be provided at the December 3, 1979, scoping meeting prior to discussing the environmental issues.

FOR FURTHER INFORMATION: BPA is now asking for suggestions and recommendations for the EIS preparation process so that concerns identified now can be fully considered in the draft EIS. Any comments or questions regarding the EIS or scoping meeting should be directed to John E. Kiley, Environmental Manager, Bonneville Power Administration, U.S. Department of Energy, P.O. Box 3621—SJ, Portland, Oregon 97208; phone (503) 234-3361, extension 5137. Copies of the BPA allocation proposal and background statement may be obtained by contacting Ms. Donna Lou Geiger, Public Involvement Coordinator, P.O. Box 12999, Portland, Oregon 97212, (503) 234-3361, extension 4261. Toll-free numbers for Oregon callers: 800-452-8429; for callers from Washington, Idaho, Montana, Utah, Nevada, Wyoming, and California: 800-547-6048.

SUPPLEMENTARY INFORMATION: The Bonneville Power Administration (BPA) is a Federal power marketing agency for the power produced primarily by 30 Federal hydroelectric projects constructed and operated by the U.S. Army Corps of Engineers and the U.S. Bureau of Reclamation. These projects and the associated BPA transmission facilities comprise the Federal Columbia River Power System (FCRPS). BPA serves 160 customers in the Pacific Northwest and the Pacific Southwest. In the Pacific Northwest alone, BPA supplies more than 50 percent of the total energy requirements. BPA serves 116 Pacific Northwest preference customers whose firm power sales contracts expire between 1983 and 1994. BPA has contracted, with certain limitations as to serving large new loads, to meet the net firm energy requirements of computed demand customers and the requirements, including contract demands, of all other existing preference customers through June 30, 1983. Bonneville has given notice under the terms of these power sales contracts that it has insufficient firm energy to supply preference customers' load growth after July 1, 1983. After that date, Bonneville will be obligated under these contracts to make available to each preference customer an allocation of firm energy determined by a formula specified in the contracts.

In addition, BPA has firm power sales contracts to sell firm energy to 17 DSI customers and 6 Federal agency customers. These power sales contracts will terminate between 1981 and 1993. As their contracts expire, the DSIs and Federal agencies may apply to their local utilities for service or make other arrangements.

The allocation formula included in preference customers' current power sales contracts does not include a method to guide the allocation of firm energy which will become available as Bonneville's existing power sales contracts expire. In addition, Bonneville has already received and expects to continue receiving applications for purchase of firm energy from newly formed public bodies and cooperatives.

The timely development of an allocation formula is important to the region's well-being. Prolonged uncertainty over the substance and mechanics of a long-term allocation policy affects the capability of customers to provide for that portion of their forecasted requirements which the BPA allocations cannot satisfy. If preference customers are overly optimistic about what their share of BPA firm energy is likely to be, shortages could occur whose impacts would vary in intensity from place to place. If preference customers are unduly pessimistic, they may construct excess generating capacity. IOUs are also affected by the uncertainty about what future requirements will be imposed on them, depending on whether or not new preference customers are formed. Some resource generating capacity is necessary to ensure reliable electric service; too much would be costly, waste resources, and unnecessarily impact the environment.

Dated: September 27, 1979.

Sterling Munro,

Administrator.

[FR Doc. 79-30856 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

Economic Regulatory Administration

Estate of S. H. Killingsworth; Proposed Remedial Order

Pursuant to 10 CFR 205.192(c), the Economic Regulatory Administration (ERA) of the Department of Energy hereby gives notice of a Proposed Remedial Order which was issued to the Estate of S. H. Killingsworth. This Proposed Remedial Order charges Killingsworth with pricing violations in the amount of $2,579,229.53, connected with the sale of crude oil and condensate at prices in excess of those permitted by 10 CFR 212, Subpart D during the time period September 1, 1973 through January 1, 1977, in the State of Texas.

A copy of the Proposed Remedial Order, with confidential information deleted, may be obtained from Wayne I. Tucker, District Manager, Southwest District Enforcement, Department of Energy, Economic Regulatory Administration, P.O. Box 35228, Dallas, Texas 75235, or by calling (214) 767-7745. On or before October 22, 1979 any aggrieved person may file a Notice of Objection with the Office of Hearings and Appeals, 2000 M Street, N.W., Washington, D.C. 20461, in accordance with 10 CFR 205.193.

Issued in Dallas, Texas, on the 27th day of September 1979.

Herbert F. Buchanan,

Deputy District Manager, Southwest District Enforcement.

[FR Doc. 79-30935 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

Atlanta Petroleum Production, Inc., Action Taken on Consent Order

AGENCY: Economic Regulatory Administration, Department of Energy.

ACTION: Notice of Action taken and opportunity for comment on Consent Order.

SUMMARY: The Economic Regulatory Administration (ERA) of the Department of Energy (DOE) announces action taken to execute a Consent Order and provides an opportunity for public comment on the Consent Order and on potential claims against the refunds deposited in an escrow account established pursuant to the Consent Order.

DATES: Effective date: September 24, 1979. Comments by: November 5, 1979.

ADDRESS: Send comments to: Wayne I. Tucker, District Manager of Enforcement, Southwest District Office, Department of Energy, P.O. Box 35228, Dallas, Texas 75235.

FOR FURTHER INFORMATION CONTACT: Wayne I. Tucker, District Manager of Enforcement, Southwest District Office, Department of Energy, P.O. Box 35228, Dallas, Texas 75235 [phone] 214/767-7745.

SUPPLEMENTARY INFORMATION: On September 24, 1979, the Office of Enforcement of the ERA executed a Consent Order with Atlanta Petroleum Production, Inc. of Fort Worth, Texas. Under 10 C.F.R. 205.199J(b), a Consent Order which involves a sum of less than $500,000 in the aggregate, excluding penalties and interest, becomes effective upon its execution.

Because the DOE and Atlanta Petroleum Production, Inc. wish to expeditiously resolve this matter as agreed and to avoid delay in the payment of refunds, the DOE has determined that it is in the public interest to make the Consent Order with Atlanta Petroleum Production, Inc. effective as of the date of its execution by the DOE and Atlanta Petroleum Production, Inc.

I. The Consent Order

Atlanta Petroleum Production, Inc., with its home office in Fort Worth, Texas, is a firm engaged in the production and sale of natural gas liquids and is subject to the Mandatory Petroleum Price and Allocation Regulations at 10 C.F.R., Parts 210, 211, 212. To resolve certain civil actions which could be brought by the Office of Enforcement of the Economic Regulatory Administration as a result of its audit of sales of NGL's, the Office of Enforcement, ERA, and Atlanta Petroleum Production, Inc. entered into a Consent Order, the significant terms of which are as follows:

1. The period covered by the audit was September 1973 through November

1976, and it included all sales of a mixed NGL stream to Warren Petroleum Corporation, Pioneer Energy Corporation, and TLOK Marketing Corporation.

2. Atlanta Petroleum Production, Inc. improperly applied the provisions of 6 C.F.R., Part 150, Subpart L, and 10 C.F.R., Part 212, Subparts E and K, when determining the prices to be charged for its NGL, and as a consequence overcharged its customers.

3. Atlanta Petroleum Production, Inc. agrees to refund to the DOE $22,500, including interest and penalty. Of this amount, $5,625 will be refunded upon the execution of this Consent Order. The remaining amount will be refunded in three payments of $5,625 each, in 60 day increments beginning 60 days after execution of this Consent Order.

4. The provisions of 10 C.F.R. 205.199J, including the publication of this Notice, are applicable to the Consent Order.

II. Disposition of Refunded Overcharges

In this Consent Order, Atlanta Petroleum Production, Inc. agrees to refund, in full settlement of any civil liability with respect to actions which might be brought by the Office of Enforcement, ERA, arising out of the transactions specified in I. 1. above, the sum of $22,500 in the manner specified in I. 3. above. Refunded overcharges will be in the form of a certified check made payable to the United States Department of Energy and will be delivered to the Assistant Administrator for Enforcement, ERA. These funds will remain in a suitable acount pending the determination of their proper disposition.

The DOE intends to distribute the refund amounts in a just and equitable manner in accordance with applicable laws and regulations. Accordingly, distribution of such refunded overcharges requires that only those "persons" (as defined at 10 C.F.R. 205.2) who actually suffered a loss as a result of the transactions described in the Consent Order receive appropriate refunds. Because of the petroleum industry's complex marketing system, it is likely that overcharges have either been passed through as higher prices to subsequent purchasers or offset through devices such as the Old Oil Allocation (Entitlements) Program, 10 C.F.R. 211.67. In fact, the adverse effects of the overcharges may have become so diffused that it is a practical impossibility to identify specific, adversely affected persons, in which case disposition of the refunds will be made in the general public interest by an appropriate means such as payment to the Treasury of the United States pursuant to 10 C.F.R. 205.199I(a).

III. Submission of Written Comments

A. *Potential Claimants:* Interested persons who believe that they have a claim to all or a portion of the refund amount should provide written notification of the claim to the ERA at this time. Proof of claims is not now being required. Written notification to the ERA at this time is requested primarily for the purpose of identifying valid potential claims to the refund amount. After potential claims are identified, procedures for the making of proof of claims may be established. Failure by a person to provide written notification of a potential claim within the comment period for this Notice may result in the DOE irrevocably disbursing the funds to other claimants or to the general public interest.

b. *Other Comments:* The ERA invites interested persons to comment on the terms, conditions, or procedural aspects of this Consent Order.

You should send your comments or written notification of a claim to Wayne I. Tucker, District Manager of Enforcement, Southwest District Office, Department of Energy, P.O. Box 35228, Dallas, Texas. You may obtain a free copy of this Consent Order by writing to the same address or by calling 214/767-7745.

You should identify your comments or written notification of a claim on the outside of your envelope and on the documents you submit with the designation, "Comments on Atlanta Petroleum Production, Inc. Consent Order." We will consider all comments we receive by 4:30 p.m. local time, on November 5, 1979. You should identify any information or data which, in your opinion, is confidential and submit it in accordance with the procedures in 10 CFR 205.9(f).

Issued in Dallas, Texas on the 28th day of Sept., 1979.

Wayne I. Tucker,

District Manager of Enforcement, Southwest District Office, Economic Regulatory Administration.

[FR Doc. 79-30932 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[ERA Case No. 52224-0273-07-77]

Potrero Unit No. 7; Pacific Gas & Electric Co.

AGENCY: Economic Regulatory Administration, Department of Energy.

ACTION: Notice of request for classification.

SUMMARY: On February 23, 1979, Pacific Gas and Electric Company (PG&E) requested the Economic Regulatory Administration (ERA) of the Department of Energy (DOE) to classify the Potrero Unit No. 7 as an existing facility pursuant to § 515.6 of the Revised Interim Rule to Permit Classification of Certain Powerplants and Installations as Existing Facilities (Revised Interim Rule) issued by ERA on March 15, 1979 (44 FR 17464) and pursuant to the provisions of the Powerplant and Industrial Fuel Use Act of 1978, 42 U.S.C. 8301 et seq. (FUA). FUA imposes certain statutory prohibitions against the use of natural gas and petroleum by new and existing electric powerplants. ERA's decision in this matter will determine whether Potrero Unit No. 7 is a new or existing powerplant. The prohibitions which apply to existing powerplants are different from those which apply to new powerplants.

The purpose of this Notice is to invite interested persons to submit written comments on this matter prior to the issuance of a final decision by ERA. In accordance with § 515.26 of the Revised Interim Rule, no public hearings will be held.

DATES: Written comments are due on or before October 26, 1979.

ADDRESSES: Ten copies of written comments shall be submitted to:

Department of Energy, Case Control Unit, Box 4629, Room 2313, 2000 M Street, N.W., Washington, D.C. 20461.

FOR FURTHER INFORMATION CONTACT:

William L. Webb (Office of Public Information), Economic Regulatory Administration, Department of Energy, 2000 M St., N.W., Room B-110, Washington, D.C. 20461, Phone: (202) 634-2170.

James W. Workman, Acting Director, Division of Existing Facilities Conversion, Economic Regulatory Administration, Department of Energy, 2000 M St., N.W., Room 3128I, Washington, D.C. 20461, Phone: (202) 254-7450.

G. Randolph Comstock (Office of the General Counsel), Department of Energy, 12th and Pennsylvania Avenue NW., Room 7134, Washington, D.C. 20461, Phone: (202) 633-8814.

Robert L. Davies, Acting Assistant Administrator, Office of Fuels Conversion, Economic Regulatory Administration, 2000 M Street NW., Room 3128-L, Washington, D.C. 20461, Phone: (202) 254-7442.

SUPPLEMENTARY INFORMATION: Pacific Gas and Electric Company (PG&E) is a corporation organized under the laws of the State of California. PG&E supplies electric service in 47 counties covering

94,000 square miles in northern and central California.

PG&E stated that it awarded an order on June 3, 1976, for the major generation equipment for the construction of a 414 MW, No. 2 oil-fired combined cycle generating plant, to be known as Potrero Unit No. 7, in the County of San Francisco, State of California, and that commercial operation is scheduled for June 1981/June 1982. On February 23, 1979, pursuant to ERA's Revised Interim Rule to Permit Classification of Certain Powerplants and Installations as Existing Facilities (Revised Interim Rule) issued by ERA on March 15, 1979, PG&E requested that ERA classify Potrero Unit No. 7 as an existing facility. A conference was held at PG&E's request on May 23, 1979.

In accordance with § 515.6 of ERA's Revised Interim Rule, a powerplant will be classified as existing if the cancellation, rescheduling or modification of the construction or acquisition of a powerplant would result in a substantial financial penalty or an adverse effect on the electric system reliability. PG&E supported its request for classification by providing evidence in support of its claim that there would be a significant impairment of system reliability if Potrero Unit No. 7 were not permitted to proceed as an oil-burning facility. A summary of the evidence requirements and PG&E's response to those requirements follows:

Adverse effect on electric system reliability—Pursuant to Section 515.6(b) of the Revised Interim Rule, ERA will classify a facility as existing upon a demonstration that the reserve margin in the electric region in which the powerplant will be located would be reduced to less than 20 percent during the 12-month period after the proposed powerplant was to begin operation, assuming that the proposed powerplant is not completed. Demonstration of an adverse effect on the utility's ability to provide service during the 12-month period following scheduled operation and/or an adverse effect on reliability after the 12-month period may also be made.

In response to the evidence requirements of § 515.7(c)(1) of the Revised Interim Rule, PG&E provided the following materials:

Description of PG&E Planning Area; list of interconnections with other utilities; projection of peak load through 1988; planned capacity resources, including net dependable electric capacity and reserve margins by years through 1988.

Power Supply Area (PSA) Region 46—Alternative Planning Area (i.e., PG&E area, Northern Nevada area, Modesto and Turlock Irrigation Districts, and State Water Project loads and resources) capacity resources, estimated loads, and reserve margins, by years through 1988.

California Energy Resources Conservation and Development Commission peak load demand forecast (1977).

Reserve margins following the projected operational date for Potrero Unit No. 7 of the June 1981 to June 1982 are stated by PG&E under several sets of assumptions and range from 10.2 to 14.1 percent.

On August 22, 1979, PG&E supplied information on hydroelectric capacity requested by ERA via letter dated July 13, 1979.

In addition to the information furnished by PG&E, ERA will consider information contained in a copy of the California Energy Resources Conservation and Development Commission's draft 1979 peak load demand forecast.

ERA hereby invites all interested persons to submit written comments on this matter.

The public file, containing PG&E's request for classification, supporting materials, and a transcript of the May 23, 1979, conference is available for inspection upon request at: ERA, Room B-110, 2000 M Street NW., Washington, D.C. 20461, Monday-Friday, 8:00 a.m.-4:30 p.m.

Issued in Washington, D.C. on October 2, 1979.

Robert L. Davies,

Acting Assistant Administrator, Office of Fuels Conversion, Economic Regulatory Administration.

[FR Doc. 79-30957 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

E.D.G., Inc. (Formerly Named Edgington Oil Co.); Proposed Consent Order

AGENCY: Economic Regulatory Administration, Department of Energy.

ACTION: Notice of Proposed Consent Order and Opportunity for Comment.

SUMMARY: The Economic Regulatory Administration (ERA) of the Department of Energy (DOE) announces a Proposed Consent Order and provides an opportunity for public comment on the proposed Consent Order and on potential claims against the refunds deposited in an escrow account established pursuant to the Consent Order.

DATE: August 17, 1979; Comments by: November 5, 1979.

ADDRESS: Send comments to: Jack L. Wood, District Manager, Western District of Enforcement, 111 Pine Street, San Francisco, CA 94111.

FOR FURTHER INFORMATION CONTACT: Jack L. Wood, District Manager, Western District of Enforcement, 111 Pine Street, San Francisco, CA 94111; Phone: (415) 556-7200.

SUPPLEMENTARY INFORMATION: On August 17, 1979, the Office of Enforcement of the ERA executed a proposed Consent Order with the Trustees for the benefit of the former shareholders of EDG, Inc., formerly named Edgington Oil Company (EDG). Under 10 CFR 205.199J(b), a proposed Consent Order which involves a sum of $500,000 or more in the aggregate, excluding penalties and interest, becomes effective only after the DOE has received comments with respect to the proposed Consent Order. Although the ERA has signed and tentatively accepted the proposed Consent Order, the ERA may, after consideration of the comments it receives, withdraw its acceptance and, if appropriate, attempt to negotiate an alternative Consent Order.

I. The Consent Order

On September 24, 1976, EDG ceased its operations as an independent refiner and marketer of a variety of petroleum products. EDG was headquartered in Los Angeles, California and during the audit period August 19, 1973 through September 24, 1976 was subject to the Mandatory Petroleum Price Regulations as set forth in Subpart E, Part 212, Title 10 CFR. To resolve certain civil actions which could be brought by the Office of Enforcement of the Economic Regulatory Administration as a result of its audit of EDG, the Office of Enforcement, ERA and the Trustees for the benefit of the former shareholders of EDG, Inc. entered into a Consent Order, the significant terms of which are as follows:

1. During the period August 19, 1973 through August 1974, DOE believes that EDG sold gasoline at prices in excess of the maximum legal selling prices to end user customers and to reseller and/or reseller-retailer customers.

2. During the period August 19, 1973 through February 1974; DOE believes that EDG sold No. 2 distillates at prices in excess of the maximum legal selling prices to end user customers and to reseller and/or reseller-retailer customers.

3. EDG by entering into this Consent Order does not admit that it has violated any regulations of the DOE.

4. The provisions of 10 CFR 205.199 J, including the publication of this Notice, are applicable to this Consent Order.

II. Disposition of Refunded Overcharges

In this Consent Order, EDG agrees to refund, in full settlement of any civil liability with respect to actions which might be brought by the Office of Enforcement, ERA, arising out of the transactions specified in Parts I.1 and I.2 above, the sum of $1,000,000.00 plus interest which will be paid within 30 days after the effective date of this Consent Order. Refund overcharges will be distributed as follows:

1. On or before 30 days following the effective date of this Consent Order, EDG shall make payments totalling $54,476.00 plus interest to identified end user customers, which payments shall be considered as full restitution and settlement of any and all civil liability within the jurisdiction of the DOE in regard to actions that might be brought by the DOE arising out of the sale of motor gasoline products and No. 2 distillates to end user customers during the period covered by this Consent Order.

2. On or before 30 days following the effective date of this Consent Order, EDG agrees to deliver a certified check made payable to the U.S. Department of Energy in the amount of $945,524.00 plus interest, considered as full restitution and settlement of any and all civil liability within the jurisdiction of the DOE in regard to actions that might be brought by the DOE arising out of the sale of motor gasoline and No. 2 distillates to reseller and/or reseller-retailer customers during the period covered by this Consent Order. Refunded overcharges resulting from sales to these customers will be in the form of a certified check made payable to the United States Department of Energy and will be delivered to the Assistant Administrator for Enforcement, ERA. These funds will remain in a suitable account pending the determination of their proper disposition. The DOE intends to distribute the refund amounts in a just and equitalbe manner in accordance with applicable laws and regulations. Accordingly, distribution of such refunded overcharges requires that only those "persons" (as defined at 10 CFR 205.2) who actually suffered a loss as a result of the transactions described in the Consent Order receive appropriate refunds. Because of the petroleum's industry complex marketing system, it is likely that overcharges have either been passed through as higher prices to subsequent purchasers or offset through devices such as the Old Oil Allocation (Entitlements) Program, 10 CFR 211.67. In fact, the adverse effects of the overcharges may have become so diffused that it is a practical impossibility to identify specific, adversely affected persons, in which case disposition of the refunds will be made in the general public interest by an appropriate means such as payment to the Treasury of the United States pursuant to 10 CFR 205.1991(a).

3. EDG offers, and agrees to pay, as a compromise, in full settlement of any civil penalties for which it may have been liable because of its conduct described herein, a compromise payment in the total amount of $50,000.00. DOE has determined that this payment is an appropriate and satisfactory compromise under the terms of 10 CFR § 205.203(b)(2) and agrees that, in the event of publication of final notice of the implementation of this Consent Order, such payment will be accepted by DOE. By this payment, EDG does not admit any violation of DOE regulations, and in consideration of this payment, when accepted, DOE hereby expressly waives its right to seek further civil penalties against EDG for such alleged violations as are included in this Consent Order. The parties understand that if this offer is not accepted by the DOE in compromise of such penalties, DOE will return the payment to EDG.

III. Submission of Written Comments

A. Potential Claimants: Interested persons who believe that they have a claim to a portion of the refund resulting from sales of products to reseller and/or reseller-retailers should provide written notification of the claim to the ERA at this time. Proof of claims is not now being required. Written notification to the ERA at this time is requested primarily for the purpose of identifying valid potential claims to the refund amount. After potential claims are identified, procedures for the making of proof of claims may be established. Failure by a person to provide written notification of a potential claim within the comment period for this Notice may result in the DOE irrevocably disbursing the funds to other claimants or to the general public interest.

B. Other Comments: The ERA invites interested persons to comment on the terms, conditions, or procedural aspects of this Consent Order.

You should send your comments or written notification of a claim to Jack L. Wood, District Manager, Western District of Enforcement, U.S. Department of Energy, 111 Pine Street, San Francisco, California 94111. You may obtain a free copy of this Consent Order by writing to the same address. You should identify your comments or written notification of a claim on the outside of your envelope and on the documents you submit with the designation "Comments on EDG Consent Order." We will consider all comments we receive by 4:30 p.m., local time on November 5, 1979. You should identify any information or data which, in your opinion, is confidential and submit it in accordance with the procedures in 10 CFR 205.9(f).

Issued in San Francisco, CA on the 22nd day of August 1979.

Jack L. Wood,

District Manager of Enforcement, Western District, Economic Regulatory Administration.

[FR Doc. 79-30858 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

Oceana Terminal Corp. et al.; Action Taken on Proposed Consent Order

AGENCY: Economic Regulatory Administration, Department of Energy.

ACTION: Notice of Proposed Consent Order and opportunity for comment.

SUMMARY: The Economic Regulatory Administration (ERA) of the Department of Energy (DOE) announces a proposed Consent Order and provides an opportunity for public comment on the proposed Consent Order and on potential claims against the refunds deposited in an escrow account established pursuant to the Consent Order.

DATE: August 22, 1979.

COMMENTS BY: November 5, 1979.

ADDRESS: Send comments to: Herbert Maletz, New York Audit Group Manager, Northeast District, 252 Seventh Avenue, New York, New York 10001.

FOR FURTHER INFORMATION CONTACT: Herbert Maletz, New York Audit Group Manager, Northeast District, 252 Seventh Avenue, New York, New York 10001, 212/620-6706.

SUPPLEMENTARY INFORMATION: On August 22, 1979, the Office of Enforcement of the ERA executed a proposed Consent Order with Oceana Terminal Corp., Cibro Sales Corp., Cibro Petroleum Products, Inc., Cibro Terminal, Inc., Cibro Petroleum/Bx., Inc., Cibro Petroleum/Bklyn., Inc., Cibro Petroleum/L.I., Inc., Cibro Gasoline Corp., Cibro Petroleum/Westchester, Inc. of Bronx, New York. Under 10 CFR § 205.199J(b), a Consent Order which involves a sum of $500,000 or more in the aggregate, excluding penalties and interest, becomes effective only after the DOE has received comments with respect to the proposed Consent Order. Although the ERA has signed and tentatively accepted the proposed Consent Order, the ERA may, after consideration of the comments it receives, withdraw its acceptance and, if appropriate, attempt to negotiate an alternative Consent Order.

I. The Consent Order

Oceana Terminal Corp., Cibro Sales Corp., Cibro Petroleum Products, Inc., Cibro Terminal, Inc., Cibro Petroleum/Bx., Inc., Cibro Petroleum/Bklyn., Inc. Cibro Petroleum/L.I., Inc., Cibro Gasoline Corp., Cibro Petroleum/Westchester, Inc. ("Cibro"), with its home offices located in the Bronx, New York, is a firm engaged in the resale and retail sale of No. 6 fuel oil and is subject to the Mandatory Petroleum Price and Allocation Regulations at 10 CFR, Parts 210, 211, 212. To resolve certain civil actions which could be brought by the Office of Enforcement of the Economic Regulatory Administration as a result of its audit of Cibro, the Office of Enforcement of the ERA, and Cibro entered into a proposed Consent Order, the significant terms of which are as follows:

1. Cibro agrees to make payments to the following classes of purchaser concerning sales of No. 6 fuel oil during the period November 1, 1973 through April 30, 1974 (audit period):

Class I—Consumer Barge.
Class II—Reseller Delivered.
Class III—Cargo-low sulphur/low por.
Class IV—Cargo-low sulphur/high por.
Class V—Retailer Rack.

2. This proposed Consent Order settles all claims and disputes between Cibro and DOE concerning Cibro's compliance with 6 CFR § 150.359(c)(i) of the Cost of Living Council ("CLC") Phase IV Regulations and 10 CFR § 212.93(a) of the DOE Regulations with respect to the computation of the maximum lawful selling price of No. 6 fuel oil sold by Cibro to the above listed classes of purchaser during the audit period.

3. This Consent Order constitutes neither an admission by Cibro that it has violated the Mandatory Petroleum Price Regulations nor a fining by ERA that Cibro has violated such regulations.

4. The provisions of 10 CFR § 205.199J, including the publication of this Notice, are applicable to the Consent Order.

II. Disposition of Refunds

In this Consent Order, Cibro agrees to refund, in full settlement of any civil liability with respect to actions which might be brought by the Office of Enforcement, ERA, arising out of the transactions specified in I.1. above, the sum of $600,000.00 over the period of one (1) year beginning September 1, 1979.

The amount to be refunded to each class is as follows:

Class I—Consumer Barge Class, $341,633.
Class II—Reseller/delivered, $60,033.
Class III—Cargo-low sulphur/low por, $21,026.
Class IV—Cargo-low sulphur/high por, $66,464.
Class V—Retailer Rack, $110,844.

In order to accomplish the above refunds to class I Cibro will issue refund checks or credit memoranda to the affected customers during the audit period. In order to accomplish the above refunds to Class II through V Cibro will issue certified checks made payable to the United States Department of Energy and delivered to the Assistant Administrator for Enforcement, ERA. These funds will remain in a suitable account pending the determination of their proper disposition.

The DOE intends to distribute the Classes II through V refunds in a just and equitable manner in accordance with applicable laws and regulations. Accordingly, distribution of such refunds requires that only those "persons" (as defined at 10 CFR § 205.2) who actually suffered a loss as a result of the transactions described in the Consent Order receive appropriate refunds. Because of the petroleum industry's complex marketing system, it is likely that overcharges, if any, have either been passed through as higher prices to subsequent purchasers or offset through devices such as the Old Oil Allocation (Entitlements) Program, 10 CFR § 211.67. In fact, the adverse effects of the overcharges, if any, may have become so diffused that it is a practical impossibility to identify specific, adversely affected persons, in which case disposition of the Class II through V refunds will be made in the general public interest by an appropriate means such as payment to the Treasury of the United States pursuant to 10 CFR § 205.199I(a).

III. Submission of Written Comments

A. *Potential Claimants:* Interested persons who believe that they have a claim to all or a portion of the Class II through V refund amount should provide written notification of the claim to the ERA at this time. Proof of claims is not now being required. Written notification to the ERA at this time is requested primarily for the purpose of identifying valid potential claims to this refund amount. After potential claims are identified, procedures for the making of proof of claims may be established. Failure by a person to provide written notification of a potential claim within the comment period for this Notice may result in the DOE irrevocably disbursing the funds to other claimants or to the general public interest.

B. *Other Comments:* The ERA invites interested persons to comment on the terms, conditions, or procedural aspects of this Consent Order.

You should send your comments or written notification of a claim to Herbert Maletz, New York Audit Group Manager, Northeast District, 252 Seventh Avenue, New York, New York 10001. You may obtain a free copy of this Consent Order by writing to the same address or by calling 212/620-6706.

You should identify your comments or written notification of a claim on the outside of your envelope and on the documents you submit with the designation, "Comments on Cibro Consent Order." We will consider all comments we receive by 4:30 p.m., local time, on November 5, 1979. You should identify any information or data which, in your opinion, is confidential and submit it in accordance with the procedures in 10 CFR § 205.9(f).

Issued in New York, New York on the 27th day of August 1979.

Herbert M. Heitzer,
Northeast District Manager of Enforcement.

[FR Doc. 79-30857 Filed 10-4-79; 8:45 am]
BILLING CODE 6450-01-M

Federal Energy Regulatory Commission

[Docket No. ER79-664]

Alabama Power Co. et al.; Filing

September 28, 1979.

Take notice that Alabama Power Company, Georgia Power Company, Gulf Power Company and Mississippi Power Company (Southern Companies) on September 17, 1979, notified the Commission that Service Schedule C of the Interchange Agreement between Southern Companies and TVA has been modified to reflect a reduction in the amount of seasonal exchange from 220,000 kw to 140,000 kw effective at the end of the year ending October 31, 1980.

Any person desiring to be heard or to protest said filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before October 19, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30875 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket Nos. ER79-549 and ER79-550]

Appalachian Power Co.; Order Accepting Rates for Filing, Suspending Proposed Rate Increases, Granting Intervention, Denying Motions, Consolidating Proceedings and Establishing Procedures

Issued: September 28, 1979.

On July 31, 1979, Appalachian Power Company (APCO) submitted for filing a proposed increase in rates for wholesale service to Kingsport Power Company (Kingsport) (Docket No. ER79-549). APCO also submitted on that date a proposed increase in rates applicable to its 20 wholesale customers (Docket No. ER79-550).[1] The proposed rates would result in increased revenues of $2,926,560 (10.5%) for Kingsport and $3,116,432 (8.4%) for its other customers, based on a twelve month period ending December 31, 1979.

Notices of the instant filings were issued on August 2, 1979, with protests or petitions to intervene due on or before August 27, 1979.

On August 13, 1979, the Tennessee Public Service Commission filed a Notice of Intervention in Docket No. ER79-549 and on August 15, 1979, the Public Service Commission of West Virginia filed a Notice of Intervention in Docket No. ER79-550.

On August 27, 1979, seven wholesale customers located in the Commonwealth of Virginia filed a petition to intervene in Docket No. ER79-550.[2] Petitioners state that after a negotiating session on August 22, 1979, representatives of APCO and the seven Virginia customers reached a settlement on a rate other than the one proposed in this filing. Petitioners state that the settlement rate is to become effective on January 1, 1980, that ratification of the settlememt by petitioners is expected soon and that, after ratification, a settlement agreement and a joint motion of APCO and its seven Virginia customers will be submitted to this Commission for approval.

On September 12, 1979, APCO filed two motions in Docket Nos. ER79-549 and ER789-550 respectively, requesting that this Commission suspend the proposed effective dates of the rate increases to January 1, 1980. In support of its motions, APCO states that it has reached a settlement with the Virginia petitioners in Docket No. ER79-550, that the parties are currently preparing settlement agreements that will be submitted to the Commission for consideration and approval, and that the settlement agreements include among other things, a compromise effective date for the settlement rate increase of January 1, 1980. APCO further states that the negotiated settlement in Docket No. ER79-550 can serve as a basis for the development of a settlement agreement in Docket No. ER79-549. Accordingly, APCO requests that the suspension periods in these dockets be limited from October 1, 1979 to January 1, 1980.

APCO states that it believes settlement is at hand with various customers who would be affected by APCO's filing. Our review indicates however, that no settlement rates or terms have yet been submitted to us for review or approval. While this Commission encourages settlement, we must base our review of APCO's proposed rates on those which have been filed with this Commission pursuant to the Federal Power Act rather than on the possibility that alternative settlement rates may or may not be filed at some date in the future. However, this action is without prejudice to the filing of a motion to shorten the suspension period if a settlement is filed with the Commission.

The Commission finds that the Virginia petitioners may be affected by any Commission action taken in this proceeding and that petitioners' interest is of such a nature that their participation may be in the public interest. We will therefore allow petitioners to intervene in this proceeding.

We also find that good cause exists to consolidate Docket Nos. ER79-549 and ER79-550. Due to common issues of law and fact, the consolidation of these dockets will save time and expense for all parties.

Our review indicates that the proposed rates have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or otherwise unlawful. Accordingly, the Commission shall accept APCO's submittals for filing and suspend the rates for five months, to become effective March 1, 1980, subject to refund pending the outcome of a hearing thereon.

The Commission orders: (A) APCO's proposed rates are hereby accepted for filing and suspended for five months, to become effective March 1, 1980, subject to refund.

(B) Docket Nos. ER79-540 and ER79-550 are hereby consolidated for the purpose of a hearing and decision thereon.

(C) The Cities of Bedford, Danville, Martinsville, Radford, Richlands and Salem, Virginia and the Virginia Polytechnic Institute and State University are hereby permitted to intervene in this proceeding subject to the Rules and Regulations of the Commission; *Provided, however,* that participation of the intervenors shall not be construed as recognition by the Commission that they might be aggrieved by any orders entered in this proceeding.

(D) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, and pursuant to the Commission's Rules of Practice and Procedure and the Regulations under the Federal Power Act (18 CFR, Chapter I) a public hearing shall be held concerning the justness and reasonableness of the rate schedules proposed by APCO in the instant dockets.

(E) The Staff shall serve top sheets in this proceeding on or before January 15, 1980.

(F) APCO's motions requesting an effective date of January 1, 1980 for its proposed rate increases are hereby denied.

(G) A presiding administrative law judge, to be designated by the Chief Administrative Law Judge for that purpose, shall convene a prehearing conference in this proceeding, to be held within 45 days of the date of this order, in a hearing room of the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. That conference shall be for the purpose of resolving any problems relating to the data requests of the staff and the intervenors. Within 10 days of the service of top sheets, the presiding administrative law judge shall convene a second prehearing conference. The presiding administrative law judge is authorized to establish procedural dates and to rule on all motions (except motions to consolidate or sever and motions to dismiss) as provided for in the Commission's Rules of Practice and Procedure.

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[1] See Attachment for rate schedule designations.

[2] The customers are: the Cities of Bedford, Danville, Martinsville, Radford, Richlands, and Salem, Virginia, and the Virginia Polytechnic Institute and State University.

(H) The Secretary shall promptly publish this order in the Federal Register.

By the Commission. Commissioner Hall was present and not voting.

Kenneth F. Plumb,

Secretary.

Attachment "A"—Appalachian Power Co., Docket Nos. ER79-549 and ER79-550

Dated: October 1, 1979.
Filed: July 31, 1979.
Instrument: Rate and Fuel Clause.

Designation and Other Party

(1) Supplement No. 3 to Rate Schedule FPC No. 23 (Supersedes Supplement No. 2)—Kingsport Power Company.
(2) Supplement No. 4 to Rate Schedule FPC No. 23.
(3) Supplement No. 3 to Rate Schedule FPC No. 75 (Supersedes Supplement No. 1)—City of Danville.
(4) Supplement No. 4 to Rate Schedule FPC No. 75 (Supersedes Supplement No. 2).
(5) Supplement No. 3 to Rate Schedule FPC No. 76 (Supersedes Supplement No. 1)—City of Martinsville.
(6) Supplement No. 4 to Rate Schedule FPC No. 76 (Supersedes Supplement No. 2).
(7) Supplement No. 3 to Rate Schedule FPC No. 78 (Supersedes Supplement No. 1)—Black Diamond Power Company (Elkhurst).
(8) Supplement No. 4 to Rate Schedule FPC No. 78 (Supersedes Supplement No. 2).
(9) Supplement No. 3 to Rate Schedule FPC No. 79 (Supersedes Supplement No. 1)—Black Diamond Power Company (East Hartland).
(10) Supplement No. 4 to Rate Schedule FPC No. 79 (Supersedes Supplement No. 2).
(11) Supplement No. 3 to Rate Schedule FPC No. 80 (Supersedes Supplement No. 1)—Black Diamond Power Company (Sophia).
(12) Supplement No. 4 to Rate Schedule FPC No. 80 (Supersedes Supplement No. 2).
(13) Supplement No. 3 to Rate Schedule FPC No. 81 (Supersedes Supplement No. 1)—Chesapeake Light & Water Company.
(14) Supplement No. 4 to Rate Schedule FPC No. 81 (Supersedes Supplement No. 2).
(15) Supplement No. 3 to Rate Schedule FPC No. 82 (Supersedes Supplement No. 1)—Elk Power Company.
(16) Supplement No. 4 to Rate Schedule FPC No. 82 (Supersedes Supplement No. 2).
(17) Supplement No. 3 to Rate Schedule FPC No. 83 (Supersedes Supplement No. 1)—Elkhorn Public Service Company (Elkhorn).
(18) Supplement No. 4 to Rate Schedule FPC No. 83 (Supersedes Supplement No. 2).
(19) Supplement No. 3 to Rate Schedule FPC No. 84 (Supersedes Supplement No. 1)—Elkhorn Public Service Company (Crozier).
(20) Supplement No. 4 to Rate Schedule FPC No. 84 (Supersedes Supplement No. 2).
(21) Supplement No. 3 to Rate Schedule FPC No. 85 (Supersedes Supplement No. 1)—Kimball Light & Water Company.
(22) Supplement No. 4 to Rate Schedule FPC No. 85 (Supersedes Supplement No. 2).
(23) Supplement No. 3 to Rate Schedule FPC No. 86 (Supersedes Supplement No. 1)—Standard Utility Service Corporation.
(24) Supplement No. 4 to Rate Schedule FPC No. 86 (Supersedes Supplement No. 2).
(25) Supplement No. 3 to Rate Schedule FPC No. 87 (Supersedes Supplement No. 1)—United Light & Power Company.
(26) Supplement No. 4 to Rate Schedule FPC No. 87 (Supersedes Supplement No. 2).
(27) Supplement No. 3 to Rate Schedule FPC No. 88 (Supersedes Supplement No. 1)—Union Power Company (Rhodell).
(28) Supplement No. 4 to Rate Schedule FPC No. 88 (Supersedes Supplement No. 2).
(29) Supplement No. 3 to Rate Schedule FPC No. 89 (Supersedes Supplement No. 1)—Union Power Company (Mullens).
(30) Supplement No. 4 to Rate Schedule FPC No. 89 (Supersedes Supplement No. 2).
(31) Supplement No. 3 to Rate Schedule FPC No. 90 (Supersedes Supplement No. 1)—War Light & Power Company.
(32) Supplement No. 4 to Rate Schedule FPC No. 90 (Supersedes Supplement No. 2).
(33) Supplement No. 3 to Rate Schedule FPC No. 92 (Supersedes Supplement No. 1)—City of Bedford.
(34) Supplement No. 4 to Rate Schedule FPC No. 92 (Supersedes Supplement No. 2).
(35) Supplement No. 3 to Rate Schedule FERC No. 93 (Supersedes Supplement No. 1)—City of Radford.
(36) Supplement No. 4 to Rate Schedule FERC No. 93 (Supersedes Supplement No. 2).
(37) Supplement No. 3 to Rate Schedule FERC No. 95 (Supersedes Supplement No. 1)—City of Salem.
(38) Supplement No. 4 to Rate Schedule FERC No. 95 (Supersedes Supplement No. 2).
(39) Supplement No. 6 to Rate Schedule FPC No. 54 (Supersedes Supplement No. 4)—Town of Richlands.
(40) Supplement No. 7 to Rate Schedule FPC No. 54 (Supersedes Supplement No. 5).
(41) Supplement No. 6 to Rate Schedule FPC No. 57 (Supersedes Supplement No. 4)—Virginia Polytechnic Institute.
(42) Supplement No. 7 to Rate Schedule FPC No. 57 (Supersedes Supplement No. 5).

[FR Doc. 79-30876 Filed 10-4-79; 8:45 am]
BILLING CODE 6450-01-M

[Docket No. ID-1821]

Joan T. Bok; Filing

September 28, 1979.

Take notice that on September 18, 1979, Joan T. Bok. (Applicant) filed an application pursuant to Section 305(b) of the Federal Power Act to hold the following positions:

Director, Massachusetts Electric Company, Public utility.

Director, The Narragansett Electric Company, Public utility.

Vice Chairman, New England Power Company, Public utility.

Any person desiring to be heard or to protest said application should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commission's rules of practice and procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before October 19, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30902 Filed 10-4-79; 8:45 am]
BILLING CODE 6450-01-M

[Docket No. FA79-33]

Robert E. Brain and Cooper & Brain, Inc., Brea Canyon Fee Lease; Extension of Time

September 25, 1979.

On September 13, 1979, Robert E. Brain and Cooper and Brain, Inc., filed a motion with the Commission to extend the time for submitting their Petition for Review of the Decision and Order of the Department of Energy issued on August 30, 1979, in the above-captioned proceeding. The motion states that the Company plans to file an appeal of the final Decision and Order in this case and also challenge the previous interlocutory decisions of the Office of Hearings and Appeals in this proceeding. Additional time has been requested so that the Company can prepare an expanded Petition for Review which will encompass these items. The motion further states that additional time is needed because of the conflicting schedule of the Company's attorney.

Upon consideration, notice is hereby given in the above-referenced proceeding that an extension of time is granted to and including October 15, 1979, for the filing of a Petition for Review in the above-referenced proceeding.

Lois D. Cashell,

Acting Secretary.

[FR Doc. 79-30877 Filed 10-4-79; 8:45 am]
BILLING CODE 6450-01-M

[Project No. 2951]

Central Hudson Gas & Electric Corp.

Application for Preliminary Permit

September 27, 1979.

Take notice that an application for preliminary permit was filed August 22, 1979, by the Central Hudson Gas & Electric Corporation [pursuant to the Federal Power Act, 16 U.S.C. Section

791(a)-825(r)] for a proposed water power project to be known as the High Falls Project, FERC No. 2951, located on Rondout Creek, a tributary to the Hudson River in the Town of Marbletown in Ulster County, New York. Correspondence with the Applicant should be directed to: Mr. Charles A. Bolz, Vice President-Engineering, Central Hudson Gas & Electric Corporation, 284 South Avenue, Poughkeepsie, New York 12602.

Purpose of Project—The power generated from this project would be fed into an existing transmission system for eventual distribution to customers of Central Hudson Gas & Electric Corporation, an investor-owned utility.

Proposed Scope and Cost of Studies Under Permit—Applicant states that a substantial amount of data has been collected and analyzed as a part of a feasibility study funded by the Department of Energy, New York State Energy Research and Development Authority, and Central Hudson. The description and assessment of existing factilities, topography, geology, and hydrology of the site have been completed.

The work proposed under the preliminary permit would include environmental analysis and other related activities needed for the preparation of an application for a FERC license. Applicant estimated the cost of the work to be performed under the preliminary permit at $75,000.

Project Description—The proposed project would redevelop the existing but inoperative High Falls Plant and would consist of: (1) a 6-foot-high concrete weir located upon the 20-foot-high natural falls; (2) a forebay formed by a 30-foot-high masonry dam adjoining the weir, containing a spillway, gated intake, and trash racks; (3) a new wood-stave penstock; (4) a new powerhouse containing s standardized package tube-type turbine-generator rated at approximately 2, 390 kW, and associated equipment; (5) a new excavated tailrace; and (6) appurtenant facilities.

Purpose of Preliminary Permit—A preliminary permit does not authorize construction. A permit, if issued, gives the Permittee, during the term of the permit, the right of priority of application for license while the Permittee undertakes the necessary studies and examinations to determine the engineering, economic, and environmental feasibility of the proposed project, the market for the power, and all other necessary information for inclusion in an application for a license. In this instance, Applicant seeks a 36-month permit.

Agency Comments—Federal, State, and local agencies that receive this notice through direct mailing from the Commission are invited to submit comments on the described application for preliminary permit. (A copy of the application may be obtained directly from the Applicant.) Comments should be confined to substantive issues relevant to the issuance of a permit and consistent with the purpose of a permit as described in this notice. No other formal request for comments will be made. If any agency does not file comments within the time set below, it will be presumed to have no comments.

Protests, and Petitions to Intervene—Anyone desiring to be heard or to make any protest about this application should file a petition to intervene or a protest with the Federal Energy Regulatory Commission, in accordance with the requirements of the Commission's Rules of Practice and Procedure, 18 CFR, §§ 1.8 or 1.10 (1978).

In determining the appropriate action to take, the Commission will consider all protests filed, but a person who merely files a protest does not become a party to the proceeding. To become a party or to participate in any hearing, a person must file a petition to intervene in accordance with the Commission's Rules.

Any protest, petition to intervene, or agency comments must be filed on or before December 3, 1979. The *Commission's address is: 825 North* Capitol Street, N.E., Washington, D.C. 20426.

The application is on file with the Commission and is available for public *inspection.*

Lois D. Cashell,

Acting Secretary.

[FR Doc. 79-30878 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-666]

Central Power & Light Co.

Application

September 28, 1979.

The filing company submits the following:

Take Notice that on September 21, 1979, Central Power & Light Company (CPL), P.O. Box 2121, Corpus Christi, Texas 78403 filed Rate Schedule T for a new interruptible, off-peak transmission service to the City of Brownsville, Texas.

Rate Schedule T is entitled "Interruptible Off-Peak Transmission Service Between Central Power & Light Company and The City of Brownsville". Pursuant to Section 35.2 of the regulations under the Federal Power Act, CPL and the City of Brownsville jointly request that the Commission waive the 60-day provision and make the interruptible transmission tariff effective as of the date of filing.

The City of Brownsville (Brownsville) has informed CPL that it has arranged for the purchase of off-peak electrical energy from Texas Power & Light Company (TPL). Further Brownsville has informed CPL that it also has arranged for the transmission of such energy by Houston Lighting and Power Company (HLP) and the Lower Colorado River Authority (LCRA) to their respective points of interconnection with CPL

Rate Schedule T provides for interruptible off-peak transmission service during the hours of 10:00 p.m. through 10:00 a.m. unless otherwise designated by Company. The duration of interruptible service may be up to, but not in excess of, 180 days. CPL's rate for providing interruptible, off-peak transmission service is 1.5 mill for each KWH of energy transmitted until City establishes its system as a separate control area in accordance with South Texas Interconnected System (STIS) criteria. Other relevant provisions of service are set forth in rate Schedule T.

Any person desiring to be heard or to protest said filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with § 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before October 19, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30879 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket Nos. RP76-13, et al.]

Cities Services Gas Company, et al., Filing of Pipeline Refund Reports and Refund Plans

September 28, 1979.

Take notice that the pipelines listed in the Appendix hereto have submitted to the Commission for filing proposed refund reports or refund plans. The date of filing, docket number, and type of filing are also shown on the Appendix.

Any person wishing to do so may submit comments in writing concerning the subject refund reports and plans. All such comments should be filed with or mailed to the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, on or before October 18, 1979. Copies of the respective filings are on file with the Commission and available for public inspection.

Kenneth F. Plumb,

Secretary.

Appendix

Filing date	Company	Docket No.	Type Filing.
Sept. 5, 1979	Cities Service	RP76-13	Report.
Sept. 11, 1979	Natural..........	RP69-36	Report.
Sept. 14, 1979	Northwest......	RP78-50	Report.
Sept. 18, 1979	El Paso..........	RP79-12	Statement.
Sept. 20, 1979	El Paso..........	CP73-334	Statement.

[FR Doc. 79-30880 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-662]

Commonwealth Edison Co.; Proposed Rate Change

September 28, 1979.

The filing company submits the following:

Take notice that Commonwealth Edison Company on September 20, 1979 tendered for filing "Amendment No. 10 to Interconnection Agreement Dated as of March 1, 1964 between Commonwealth Edison Company and Illinois Power Company" and "Appendix 'I' to Facility Use Agreement between Commonwealth Edison Company and Illinois Power Company."

Amendment No. 10 provides primarily for an increase in the Short Term Power weekly demand charge for said interconnection transactions. Appendix "I" provides for a new point of interconnection between the Parties.

Copies of the filing were served upon Illinois Power Company, Decatur, Illinois and the Illinois Commerce Commission, Springfield, Illinois.

Any person desiring to be heard or to protest said application should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before October 19, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30881 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ES79-67]

Gulf States Utilities Co.; Application

September 27, 1979.

Take notice that on September 12, 1979, Gulf States Utilities Company (Applicant) filed an application seeking an order pursuant to Section 204(a) of the Federal Power Act authorizing the issuance of $200,000,000 principal amount of unsecured short-term promissory notes. Applicant is incorporated under the laws of Texas with its principal business office at Beaumont, Texas, and is engaged in the electric utility business in portions of Louisiana and Texas. Natural gas is purchased at wholesale and distributed at retail in the City of Baton Rouge, Louisiana and vicinity.

The proceeds from the Notes will be added to the general funds of the Applicant and will be used, among other things, to provide part of the interim funds for current construction expenditures made and to be made.

Any person desiring to be heard or to make any protest with reference to said application should on or before October 15, 1979, file with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, petitions to intervene or protests in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Persons wishing to become parties to a proceeding or to participate as a party in any hearing therein must file petitions to intervene in accordance with the Commission's rules. The application is on file with the Commission and available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30882 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-667]

Kansas City Power & Light Co.; Proposed Change in Rate

September 28, 1979.

Filing company submits the following:

Take notice that on September 21, 1979, Kansas City Power & Light Company (KCPL) tendered for filing a Municipal Wholesale Firm Power Contract dated June 7, 1979, between KCPL and the City of Salisbury, Missouri. KCPL requests an effective date sixty (60) days after filing. The Contract terminates the Municipal Wholesale Firm Power Contract, dated August 10, 1967, KCPL Rate Schedule FPC No. 61, and provides for rates and charges for wholesale firm power service by KCPL to the City of Salisbury.

KCPL states that the proposed rates are KCPL's rates and charges for similar service under schedules previously submitted by KCPL to the Federal Energy Regulatory Commission.

Any person desiring to be heard or to protest said filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before October 19, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30886 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket Nos. ER76-131, ER76-552 and ER78-25]

Kansas City Power & Light Co.; Filing Proposed Settlement Agreement

September 26, 1979.

Please take notice that on June 19, 1979, the Kansas City Power & Light Company (KCPL), filed an executed settlement agreement providing for transmission service by KCPL for the Cities of Osawatomie, and Garnett, Kansas and the City of Kansas City, Kansas, Board of Public Utilities.

Any person desiring to be heard or to protest said settlement should file comments with the Federal Energy Regulatory Commission, 825 North

Capitol Street, N.E., Washington, D.C. 20426, on or before October 10, 1979. Comments will be considered by the Commission in determining appropriate action to be taken. Copies of the settlement proposal are on file with the Commission and are available for public inspection.

Lois D. Cashell,

Acting Secretary.

[FR Doc. 79-30885 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-535]

Kansas City Power & Light Co.; Order Accepting Rates for Filing and Suspending Proposed Rate Increase

Issued: September 25, 1979.

On July 26, 1979, Kansas City Power and Light Company (KCPL) submitted for filing a proposed increase in rates for wholesale service to Kansas Gas and Electric Company (KG&E).[1] The proposed increase reflects a pass through of an identical increase in peaking capacity and energy charges placed in effect for the Southwestern Power Administration (SPA) on an interim basis by the Assistant Secretary for Resource Applications of the Department of Energy. Peaking capacity and energy are supplied to KCPL by SPA. KCPL in turn supplies a portion of that peaking capacity and energy to KG&E.

In the filing, KCPL states that no transactions between KCPL and SPA are anticipated after May 31, 1979, because on that date peaking capacity and energy from SPA became unavailable. KCPL billing data shows that the total increase to KG&E for the months of April and May 1979, was $46,066 (35.5%). KCPL has requested waiver of notice requirements and an effective date of April 1, 1979, the date SPA's higher rates became effective on an interim basis.

Notice of the filing was issued on August 2, 1979, with protests or petitions to intervene due on or before August 20, 1979. No protests or petitions have been received.

On December 21, 1978, the Secretary of Energy issued an order [2] delegating to the Assistant Secretary for Resource Applications the authority to develop, confirm, approve and place into effect, on an interim basis, power and transmission rates for the federal power marketing administrations. The order delegated to the Commission the authority to confirm and approve on a final basis, or to disapprove, rates developed by the Assistant Secretary.

Pursuant to the Delegation Order, the Assistant Secretary approved on an interim basis SPA's revised Rate Schedule P-3 which is the rate schedule under which SPA sells peaking power and energy to KCPL.[3] As indicated above, KCPL's proposed rates in the instant filing are identical to the SPA rates and the company is merely passing the higher rates on to KG&E.

SPA's proposed rate increase utlimately may be disapproved by the Commission and a lower rate subsequently approved.[4] As a result, SPA may be required to make refunds to KCPL. In such a case, we would require KCPL to reduce its rates and make appropriate refunds to KG&E. Accordingly, we believe that the proposed filing should be suspended for one day and made subject to refund pending the outcome of this Commission's final determination of the P-3 rate.

Because of the above circumstances, we are unable to conclude that the proposed rates have been shown to be just and reasonable. Therefore, the Commission will accept KCPL's submittal for filing and suspend the rates for one day to become effective April 2, 1979, subject to refund.

The Commission orders: (A) KCPL's request for waiver of the notice requirements of Section 35.3 of our Regulations is hereby granted.

(B) KCPL's proposed increase is accepted for filing and suspended for one day to become effective April 2, 1979, subject to refund.

(C) KCPL's proposed increase is expressly made subject to the outcome of this Commission's proceedings relative to Southwestern Power Administration's Rate Schedule P-3. Within sixty (60) days after the receipt of any refunds by KCPL relating to the adjudication of Rate Schedule P-3, KCPL shall file with the Commission a report of refunds owed to KG&E in this docket.

(D) The Secretary shall promptly publish this order in the Federal Register.

By the Commission.

Kenneth F. Plumb,

Secretary.

Attachment A

Rate Schedule Designations

Kansas City Power & Light Company—(1) Supplement No. 1 to Rate Schedule FPC No. 31c.

Kansas Gas and Electric Company—(2) Supplement No. 1 to Rate Schedule FPC No. 88 (Concurs in (1) above).

[FR Doc. 79-30884 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[1] See Attachment for Rate Schedule Designations.

[2] Delegation Order No. 0204-33.

[3] See Department of Energy Rate Order No. SWPA-1, "Order Confirming, Approving, and Placing Increased Power Rates in Effect On An Interim Basis" (March 1, 1979). Schedule P-3 became effective on an interim basis on April 1, 1979.

[4] This should not be taken to imply any prejudgment concerning the reasonableness of the SPA rates. That matter has not yet been reviewed by the Commission.

[Docket No. E-9520]

Illinois Power Co.; Refund Report

September 27, 1979.

Take notice that Illinois Power Company on September 13, 1979 tendered for filing a Report of Distribution of Refunds made by Illinois Power to the City of Oglesby, Illinois and the Cedar Point Light & Water Company on August 27, 1979 and the Village of Ladd, Illinois on August 28, 1979.

Any person desiring to be heard or to protest said filing should file a protest with the Federal Power Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8 and 1.10). All such protests should be filed on or before October 15, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30883 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER78-1]

Kansas Power & Light Co.; Compliance Filing

September 26, 1979.

Take notice that Kansas Power & Light Company on August 20, 1979, tendered for filing a revised rate schedule for wholesale service to municipalities (WSM-78 REVISED) as required by the Commission's order issued August 2, 1979.

Any person desiring to be heard or to protest said filing should file a protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8 and 1.10). All such protests should be filed on or before October 5, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken. Copies of this filing are on file with the Commission and are available for public inspection.

Lois D. Cashell,

Acting Secretary.

[FR Doc. 79-30887 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-660]

The Montana Power Co.; Filing

September 27, 1979.

The filing Company submits the following:

Take notice that on September 21, 1979, the Montana Power Company tendered for filing in compliance with the Federal Power Commission's Order of May 6, 1977, a summary of sales made under the Company's FPC Electric Tariff M-1 during August, 1979, along with cost justification for the rate charged.

Any person desiring to be heard or to protest said filing should file a protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commission's Rules of Practice and procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before October 15, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30888 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. CP79-182]

Natural Gas Pipeline Co. of America; Findings and Order After Statutory Hearing Issuing Certificate of Public Convenience and Necessity and Granting Petitions To Intervene

September 27, 1979.

On February 12, 1979, Natural Gas Pipeline Company of America (Natural)[1] filed in Docket No. CP79-182 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing Natural to acquire from Chevron U.S.A. Inc. (Chevron) certain ownership interests in producer-installed pipeline and compression facilities, offshore Louisiana, all as more fully set forth in the application.

Natural proposes to acquire, retain in place, and operate the following facilities constructed by Chevron:

(1) Eugene Island Block 305 gathering line (EI 305)—50 percent interest in approximately 2.1 miles of 6-inch pipeline connecting platforms A and B.

(2) Vermilion Block 214 gathering line (V 214)—approximately 3200 feet of 6-inch pipeline connecting platforms A and B.

(3) West Cameron Block 534 compression (WC 549)—75 percent interest in two 1,100 horsepower compressor units.

(4) West Cameron Block 549 compression (WC 549)—40 percent interest in two 1,100 horsepower compressors.

The 6-inch pipeline in EI 305 was constructed by Chevron to connect the A and B platforms of which 50 percent is owned by Chevron and the remaining 50 percent by Mobil Oil Company (Mobil). The interests of Chevron and Mobil are dedicated to Natural. Under the terms of the gas purchase contract between Natural and Chevron, the B platform was designated as the initial delivery point in EI 305 and Natural constructed the facilities necessary to provide the pipeline connection to this point. However, a second platform, A, was utilized further to develop the block. The terms of the gas purchase contract require Natural to provide a pipeline connection to an additional delivery point if the reserves available at that point total at least 3,000,000 Mcf for each additional mile of pipeline required. Natural avers that approximately 21,700,000 Mcf of gas (11,400,000 Mcf dedicated by Chevron and 10,300,000 Mcf dedicated by Mobil) will be produced on the A platform and will flow through the 6-inch line connecting the A and B platform. Chevron constructed the additional line to facilitate the initial deliveries of gas from the A platform and thus eliminate the need for Natural to construct an additional connection and meter installation for the A platform.

Natural proposes to acquire approximately 3,200 feet of 6-inch pipeline connecting the A and B platforms in V 214, which was constructed and is owned by Chevron. under the gas purchase contract between Natural and Chevron, platform A was designated as the original delivery point. A second platform, B, was utilized further to develop the block. Natural is required, under the terms of this contract to provide a pipeline connection to an additional delivery point if the reserves available at that point equal at least 8,000,080 Mcf for each additional mile of pipeline required. Natural states that approximately 29,100,000 Mcf of dedicated reserves will be made available and produced through the above mentioned 6-inch pipeline connecting the A and B platforms. Chevron constructed the additional line to facilitate the deliveries of gas from this block and thus eliminate the need for Natural to construct an additional connection and meter installation for the B platform.

In WC 534, Natural proposes to acquire a 75 percent interest in Chevron's 100 percent interest in two 1,100 horsepower compressors installed by Chevron in WC 534 and to provide 75 percent of the fuel required to operate the compressors.[2] Under the terms of the gas purchase contract between Natural and Chevron, if in the opinion of the parties compression is economically feasible, Natural will provide such compression at no charge to Chevron. Chevron is to provide platform space, install, operate, and maintain said compressors at no charge to Natural. Natural states that without the compression provided herein, the reserves in WC 534 would be subject to drainage from production of gas in WC 532 and 533, thereby reducing the reserves available. Approximately 7,300,000 Mcf of additional gas will ultimately be produced and made available to Natural's customers as a result of this compression.

Natural proposes to acquire from Chevron, a 40 percent interest in two 1,100 horsepower compressors installed by Chevron on a platform in WC 564 to compress gas from WC 549 and 564.[3] Approximately 40 percent of the installation costs of facilities located on WC 564 have been allocated to WC 549 and 60 percent to WC 564. Under the terms of the gas purchase contract between Natural and Chevron, if in the opinion of the parties, compression is economically feasible, Natural will

[1] Natural, a Delaware corporation having its principal place of business in Chicago, Illinois, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by order issued October 13, 1942, in Docket No. G-235 (3 FPC 830).

[2] Since the gas from this block is connected to the Stingray Pipeline system, Natural is required by the partnership agreement to assign 25 percent of any gas production and facility costs to Trunkline Gas Company.

[3] Natural purchases 100 percent of the reserves in WC 564 from Chevron. Natural indicates that a filing to purchase 60 percent of these facilities will be made at a later date.

provide such compression at no cost. Chevron is to provide platform space, install, operate and maintain said compressors at no charge to Natural and presumably Natural will furnish its share of fuel volumes., Natural states that the addition of this compression for WC 549 will result in an increase of about 8,000,000 Mcf producible reserves.

Natural is also obligated by the above agreement to provide dehydration facilities attributable to WC 549. These facilities are also located on WC 564 and 40 percent of their costs have been allocated to WC 549. Natural avers that the dehydration facilities fall under Section 2.55 of the Commission's General Policy and Interpretations and therefore acquisition is excluded from this filing.

The facilities and their associated are as follows:

Area	Costs
EI 305	$336,226
V 214	241,870
WC 534	699,146
WC 549	420,641
40 percent interest in dehydration facilities	179,297
Total	$1,877,180

Natural states that the cost of acquiring the facilities herein will be met from funds on hand and that these facilities will be depreciated in accordance with the depreciation policy in effect on existing facilities.

With respect to the cost of compression facilities allocated to WC 534 and WC 549 to be acquired, should Natural seek to include these costs in its jurisdictional rates, it will be required to show that such costs are not compensated for in the applicable producer ceiling price. This is consistent with action taken in Docket Nos. CP77-558 and CP77-577 which involved offshore compression facilities installed on a production platform. Although Natural does not request authority for the acquisition of a portion of the dehydration facilities in WC 549, it is noted that the certificate issued to Chevron in Docket No. CI78-853 contains a similar caveat concerning the treatment of costs associated with processing, dehydration, compression or other conditioning of the gas.

Since Chevron has booked no depreciation on the facilities to be acquired, Natural is purchasing all the facilities at Chevron's original costs. Therefore, original cost and depreciated book value are the same.

Since the offshore pipeline and compression facilities will be used for the transportation of natural gas in interstate commerce subject to the jurisdiction of the Commission, said acquisition thereof is subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

After due notice by publication in the Federal Register on March 13, 1979 (44 FR 14624), timely petitions to intervened were filed by Associated Natural Gas Company and Central Illinois Light Company. No further petitions to intervene, notices of intervention, or protests to the granting of the application have been filed.

At a hearing held on September 19, 1979, the Commission on its own motion received and made a part of the record in this proceeding all evidence, including the application and exhibits thereto, submitted in support of the authorization sought herein, and upon consideration of the record.

The Commission finds: (1) Natural is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(2) The proposed acquisition of offshore pipeline and compression facilities is required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(3) Participation in this proceeding by Associated Natural Gas Company and Central Illinois Light Company may be in the public interest.

The Commission orders: (A) Upon the terms and conditions of this order, a certificate of public convenience and necessity is issued to Natural in Docket No. CP79-182 authorizing the acquisition of various interests in certain offshore pipeline and compression facilities, as hereinbefore described and as more fully described in the application.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Natural's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (d)(2), (d)(3), and (e) of Section 157.20 of such Regulations.

(C) Should Natural seek to recover the related costs of the compression and dehydration facilities in its jurisdictional rates, it will be required to show that these costs have not been compensated for in the ceiling rate applicable to the producer sale. This condition is subject to the outcome of the rehearing in Docket Nos. CI77-412, CP77-558 and CP77-577.

(D) In accordance with its rate schedules, Chevron is to operate and maintain the compressors at no cost to Natural.

(E) The aquisitions authorized herein shall be consummated, as provided by paragraph (b) of Section 157.20 of the Regulations under the Natural Gas Act, within one year from the date of this order.

(F) Associated Natural Gas Company and Central Illinois Light Company are permitted to intervene in this proceeding sugject to the Rules and Regulations of the Commission; *Provided, however,* that the participation of such interveners shall be limited to matters affecting asserted rights and interests as specifically set forth in their petitions to intervene; and, *Provided, further,* that the admission of said interveners shall not be construed as recognition by the Comnmission that they may be aggrieved because of any order of the Commission entered in said proceeding.

By the Commission.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30889 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. CP79-232]

Natural Gas Pipeline Co. of America et al.; Findings and Order After Statutory Hearing Issuing Certificate of Public Convenience and Necessity; Certificate (Construction)

Issued: September 27, 1979.

On March 20, 1979, Natural Gas Pipeline Company of America (Natural),[1] Transcontinental Gas Pipe Line Corporation (Transco),[2] and Texas Eastern Transmission Corporation (Texas Eastern)[3] filed in Docket No. CP79-232 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of 4.9 miles of 12¾ inch pipeline and appurtentant facilities offshore Louisiana, all as more fully set forth in the application.

[1] Natural, a Delaware corporation having its principal place of business in Chicago, Illinois, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by order issued October 13, 1942, in Docket No. G-235 (3 FPC 830).

[2] Transco, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by order issued November 18, 1948, in Docket No. G-1143 (7 FPC 145).

[3] Texas Eastern, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by order issued October 11, 1947, in Docket No. G-880 (6 FPC 171).

Applicants request authorization to construct and operate 4.9 miles of 12¾-inch pipeline and appurtenant facilities in the West Cameron Area from Block 540 to a subsea tie-in on the Stingray system located in Block 550. The proposed facilities will be constructed, managed, and operated by Natural and will be jointly owned by the Applicants according to the following percentages: Natural 25 percent; Transco 48 percent; Texas Eastern 18 percent; and uncommitted 9 percent. Costs associated with the uncommitted 9 percent will be prorated among the Applicants in accordance with their respective percentages of ownership in the event commitment is not secured prior to certification.[4]

Natural's Block 540 gas will be transported and redelivered onshore through its capacity in Stringray pursuant to Stingray's Rate Schedule T-1. Transco is said to be negotiating a transportation agreement with Trunkline Gas Company (Trunkline) by which Transco will utilize a portion of Trunkline's capacity entitlement in Stingray. Tennessee Gas Pipeline Company, a Division of Tenneco Inc. (Tennessee), and Texas Eastern are said to be negotiating a transportation and exchange agreement relating to capacity available to Tennessee in Stingray which would allow for the receipt and delivery of Texas Eastern's gas to its system.

Natural's 25 percent interest of the committed reserves is from Marathon Oil Company (Marathon). Transco's 48 percent interest is from Louisiana Land and Exploration Company (Louisiana Land) and Louisiana Land Offshore Exploration Company (Louisiana Offshore) through Transco's affiliate Transco Gas Supply Company (Gasco). Texas Eastern's 18 percent interest of the committed reserves is from Texas Eastern Exploration Company.

Natural is said to be negotiating a contract with Marathon which will be submitted upon execution by the parties prior to placing the proposed facilities in service.

Transco has obtained, from Louisiana Land and Louisiana Offshore, the preferential right to purchase reserves in Block 540. Such agreements were subsequently assigned to Gasco which is said to be continuing negotiations with Louisiana Land and Louisiana Offshore for a contract which will be submitted upon execution prior to the facilities being placed in service. Gasco will resell the gas to Transco.

Applicants estimate the total cost of the proposed project to be $3,627,400 which will be financed initially through revolving credit arrangements, short-term loans, and from cash on hand. Permanent financing will be undertaken as part of Applicants' respective overall long-term financing programs at a later date.

Approval of this application does not constitute a major federal action significantly affecting the quality of the human environment since the proposed pipeline would be located approximately 100 miles from the Louisiana coastline in water depths ranging from 185 to 195 feet. However, construction would cause a minor, temporary increase in turbidity and disruption of benthic life.

Since the proposed facilities will be used for the transportation of natural gas in interstate commerce subject to the jurisdiction of the Commission, the construction and operation thereof are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

After due notice by publication in the Federal Register on April 13, 1979 (44 FR 22136), no petition to intervene, notice of intervention, or protest to the granting of the application has been filed.

At a hearing held on September 19, 1979, the Commission on its own motion received and made a part of the record in this proceeding all evidence including the application and exhibits thereto, submitted in support of the authorization sought herein, and upon consideration of the record.

The Commission finds: (1) Natural, Transco, and Texas Eastern are able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(2) The proposed construction and operation by Applicants are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

The Commission orders: (A) Upon the terms and conditions of this order, a certificate of public convenience and necessity is issued authorizing Natural, Transco, and Texas Eastern to construct and operate 4.9 miles of 12¾-inch pipeline and appurtenant facilities, as hereinbefore described and as more fully described in the application.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicants compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (c)(3), (c)(4), (e) and (f) of Section 157.20 of such Regulations.

(C) The facilities authorized by paragraph (A) above shall be constructed and placed in actual operation, as provided by paragraph (b) of Section 157.20 of the Regulations under the Natural Gas Act, within one year from the date of this order.

(D) The certificate issued by paragraph (A) above is conditioned upon the filing by the producers of certificate applications or letters of commitment covering the sale of gas as set forth in the appendix hereto.

(E) The subject facilities shall not be accorded rate base treatment by Transco and Texas Eastern until all requisite authorizations necessary to implement the movement of the subject gas onshore are granted.

(F) The authorization granted herein is conditioned upon the filing of an agreement prior to the commencement of operation of authorized facilities, which provides for construction, ownership, operation, and maintenance as represented in the application.

By the Commission.

Kenneth F. Plumb,

Secretary.

Appendix

The filing of a related producer certificate application or written commitment to sell the gas covered by such application to Applicant is required. This commitment shall be verified under oath by a responsible official of the company and shall be filed in the pipeline docket. The commitment shall contain the producer's agreement to

(a) Accept a certificate conditioned to the applicable maximum lawful price prescribed in the Natural Gas Policy Act of 1978 or the contract rate, whichever is lower.

(b) File a rate schedule that complies with all the applicable rules and regulations including Sections 154.93 and 154.103 of the Regulations under the Natural Gas Act.

The written commitment shall identify the acreage or blocks and depths from which the gas is to be produced and delivered, identify the present estimate of recoverable reserves and deliverability from the acreage, and include the sworn statement of an authorized official of the producer that it assumes a binding obligation to deliver the gas produced from the acreage to the subject pipeline company within a reasonable time of receipt of appropriate certificate authorization covering the sale of such gas and the completion of the pipeline's facilities constructed to receive and transport such gas.

If the producer contemplates filing under the optional procedure, the commitment shall contain the producer's agreement

[4] The construction, ownership, operation, and maintenance agreement was not filed as part of the application. Applicants state that it will be submitted when all of the gas is committed.

(a) That the gas covered by the related contract will be sold to the Applicants and no other purchaser.

(b) Deliveries will commence within a reasonable time of completion of the Applicants' facilities.

(c) To continue the sale of natural gas to Applicants pursuant to the related contract and any amendment and supplement thereto agreed to by the parties or any successor agreement.

(d) In the event a certificate is not issued or accepted, or in the event that future Commission action or non-action is otherwise not effective to authorize the sale of gas, to have on file an application pursuant to the applicable Rules and Regulations of the Commission and such other lawful orders of the Commission as may be issued in the future.

[FR Doc. 79-30890 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-665]

New Bedford Gas & Edison Light Co.; Proposed Termination of Rate Schedule

September 28, 1979.

The filing company submits the following: Take notice that on September 20, 1979 New Bedford Gas and Edison Light Company (New Bedford) filed a Notice of Termination for its currently effective Federal Energy Regulatory Commission Rate Schedule No. 28. Said Rate Schedule Consists of a unit power sales agreement dated March 10, 1978, between New Bedford Gas and Edison Light Company and the Vermont Marble Co., Inc. (Marble) for the sale by New Bedford of a portion of its entitlement to the capacity and related energy produced by Canal Electric Company's Unit No. 2.

FERC Rate Schedule No. 28 was originally accepted for filing by FERC letter order dated October 4, 1978 in Docket No. ER78-543. FERC Rate Schedule No. 28 became effective November 1, 1978 and will terminate by its own provisions on October 31, 1979. New Bedford has requested the Commission to waive its notice requirements pursuant to Section 35.15 of its Regulations and to permit the tendered Notice of Termination to become effective as of October 31, 1979, the final day upon which service will be rendered under Rate Schedule No. 28.

A copy of this filing has been mailed to Vermont Marble Co., Inc.

Any person desiring to be heard or to protest said filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before October 19, 1979. Protests will be considered by the Commission in determining the Appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30891 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-663]

New Bedford Gas & Edison Light Co.; Filing of Unit Power Sale Rate Schedule

September 28, 1979.

The filing company submits the following: Take notice that on September 21, 1979 New Bedford Gas and Edison Light Company ("New Bedford") filed a rate schedule governing the sale by New Bedford of a portion of its entitlement to capacity and related energy produced by Canal Electric Company's Unit No. 2 ("the Unit"). Said filing was made pursuant to Section 35.12 of the *Regulations Under the Federal Power Act.*

By the provisions of the tendered rate schedule, New Bedford proposes to sell to the Vermont Marble Company, Inc. 0.3425% of the Net Capability of the Unit (as defined at Article III of the tendered rate schedule) plus the energy related thereto for a twelve-month period beginning November 1, 1979.

A copy of this filing has been served upon Marble.

Any person desiring to be heard or to protest said filing should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commission's rules of practice and procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before October 19, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30892 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket Nos. CP78-123, et al.]

Northwest Alaskan Pipeline Co.; Meeting Regarding Cost Estimates

October 2, 1979.

Take notice that the Commission's Alaskan Delegate appointed by the Commission's order of December 16, 1977,[1] and/or his representatives will provide a briefing on his recent meetings with the sponsors of both segments of the "pre-build project".[2] The "pre-build project" is currently the subject of an ongoing adjudicatory proceeding in Docket Nos. CP78-123, *et al.* The delegate's meeting is being held to discuss the Certification Cost and Schedule Estimates required to be filed in that proceeding by Commission order of September 6, 1979.[3]

The following meeting is scheduled:

October 9, 9 a.m.—Federal Energy Regulatory Commission, 825 North Capitol St., N.E., Washington, D.C., Room number to be posted.

This meeting will be open to parties to the adjudicatory proceeding in this docket or any interested member of the general public. If interested call Miss Jeanne Barrie for further information at (202) 275-3827.

John B. Adger, Jr.,

Alaskan Delegate.

[FR Doc. 79-30901 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[1] "Order Vacating Prior Proceedings and Issuing Conditional Certificates of Public Convenience and Necessity," Docket Nos. CP78-123, 124, and 125 (Issued December 16, 1977).

[2] The "pre-build project" is a proposal to construct certain of the facilities of the Alaskan Natural Gas Transportation System, approved by the President and the Congress pursuant to the provisions of the Alaska Natural Gas Transportation Act, in advance of when they would be required for Alaska gas service for use in delivering net new imports of Canadian gas.

[3] "Order on Procedures for Cost Estimates," Docket Nos. CP78-123, *et al.* (Issued September 6, 1979.)

[Docket No. ER79-661]

Northwestern Public Service Co.; Filing

September 27, 1979.

The filing Company submits the following:

Take notice that on September 14, 1979, Northwestern Public Service Company (NWPS) tendered for filing, in accordance with Section 35.13 of the

Commission's regulations, a proposed tariff change under which it provides supplemental service to certain municipal and government operated systems within the State of South Dakota. Pursuant to the rate schedule, NWPS will provide capacity and energy that applicable customers cannot obtain from their principal supplier, the Western Area Power Administration (WAPA) due to certain load restrictions imposed by WAPA which became effective November 1, 1977.

NWPS requests that the change be made effective November 15, 1979. The change, which principally reflects the costs associated with the operations of a new generating facility (Neal No. 4), would increase revenues from jurisdictional sales and service by $33,244 based on the twelve month period ended October 31, 1979.

NWPS had served copies of the filing upon the State of South Dakota, the South Dakota Public Utilities Commission, and participating customers.

Any person desiring to be heard or to make application with reference to said application should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 in accordance with Sections 1.8 and 1.10 of the Commission's rules of practice and procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before October 15, 1979. Protest will be considered by the Commission in determing the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30893 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ES79-66]

Oklahoma Gas & Electric Co.; Application

September 27, 1979.

Take notice that on September 12, 1979, Oklahoma Gas and Electric Company (Applicant) filed an application pursuant to Section 204 of the Federal Power Act seeking an order authorizing the issuance of unsecured Promissory Notes to commercial banks and to commercial paper dealers in amounts not exeeding in the aggregate $150,000,000 outstanding at any one time.

Applicant is incorporated under the laws of the Territory of Oklahoma with its principal business office at Oklahoma City, Oklahoma, and is engaged primarily in the electric utility business in Oklahoma and Arkansas.

The proceeds from the issuance of the Notes will be added to the general funds of the Applicant, which general funds will be used, among other things, to finance in part the Applicant's 1980 and 1981 construction program. Applicant estimates that construction expenditures for the year ending December 31, 1980 will total about $162,000,000 and for the year ending December 31, 1981 will total about $211,000,000.

Any person desiring to be heard or to make any protest with reference to said application should, on or before October 15, 1979, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, petitions or protest in accordance with the requirement of the Commission's rules of practice and procedure (18 CFR 1.8 or 1.10). The application is on file and available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30894 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-658]

Pacific Power & Light Co.; Rate Schedule Filing

September 27, 1979.

Take Notice that Pacific Power & Light Company (Pacific) on September 18, 1979, tendered for filing, in accordance with Section 35.12 of the Commission's Regulations, a new rate schedule for power sales to the Salt River Project Agricultural Improvement and Power District (Salt River). Under this schedule Pacific supplies firm thermal energy to Salt River.

Pacific requests waiver of the Commission's notice requirements to permit this rate schedule to become effective September 13, 1979, which it claims is the earliest date for commencement of service.

Copies of the filing were supplied to Salt River.

Any person desiring to be heard or to protest said application should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before October 15, 1979. Protests will be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30895 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ID-1884]

Donald G. Pardus; Notice of Filing

September 28, 1979.

Take notice that on September 21, 1979, Donald G. Pardus, (Applicant) filed an application pursuant to Section 305(b) of the Federal Power Act to hold the following positions:

Director, vice president, assistant treasurer, and assistant secretary, Blackstone Valley Electric Company, public utility.

Director, vice president, assistant treasurer and assistant clerk, Eastern Edison Company, public utility.

Director, vice president, assistant treasurer and assistant clerk, Montaup Electric Company, public utility.

Any person desiring to be heard or to protest said application should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with Sections 1.8 and 1.10 of the Commission's Rules of Practice and Procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before October 19, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30898 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER79-659]

Southern California Edison Co.; Filing of Rate Schedule Change

September 27, 1979.

The filing Company submits the following:

Take notice that Southern California Edison Company ("Edison"), on

September 18, 1979, tendered for filing Amendment No. 1 To The Edison-Pasadena Interruptible Transmission Service Agreement No. 9987 (the "Agreement") with the City of Pasadena ("Pasadena") which provides for an increase in the maximum rates of delivery of interruptible transmission service to Pasadena. Edison states that all other terms and conditions of Rate Schedule FERC No. 88 as supplemented will remain in full force and effect.

Edison states that Pasadena requests that service be initiated at the earliest possible date under this Agreement, and for that reason Edison requests that the prior notice requirements of the Commission's regulations be waived and the filing be permitted to become effective as soon as possible.

Copies of this filing were served upon City of Pasadena and the Public Utilities Commission of the State of California.

Any persons desiring to be heard or to protest this application should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with § 1.8 and § 1.10 of the Commission's rules of practice and procedure (18 CFR 1.8, 1.10). All such petitions or protests should be filed on or before October 15, 1979. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30897 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER-79-646]

Virginia Electric & Power Co.; Contract Supplement

September 27, 1979.

The filing Company submits the following:

Take notice that on September 10, 1979, Virginia Electric and Power Company (VEPCO) tendered for filing a Contract Supplement dated August 8, 1979 to the Rate Contract between VEPCO and the Virginia Electric Cooperative.

Said Supplement requests the Commission's authorization for connection of the new delivery point designated as Bear Island Delivery Point, located in Hanover County, Virginia.

VEPCO requests an effective date for the new delivery point as that of the date of connection of the new facilities which is expected to occur sometime in October, 1979.

Any person desiring to be heard or to make any protest with reference to said application should on or before October 15, 1979, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, petitions to intervene or protests in accordance with the requirements of the Commission's rules of practice and procedure (18 CFR 1.8 or 1.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Persons wishing to become parties to a proceeding or to participate as a party in any hearing herein must file petitions to intervene in accordance with the Commission's Rules. The application is on file with the Commission and is available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30898 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Project No. 2955]

The City of Watervliet, New York; Application for Preliminary Permit

September 27, 1979.

Take notice that an application for preliminary permit was filed August 23, 1979, by the City of Watervliet, New York [pursuant to the Federal Power Act, 16 U.S.C. Section 791(a)-825(r)] for a proposed water power project to be know as the Normans Kill Project, FERC No. 2955, located on Normans Kill, a tributary to the Hudson River in the Town of Guilderland in Albany County, New York. Correspondence with the Applicant should be directed to: Mr. Michael E. Gilchrist, General Manager, City Hall, Watervliet, New York 12189.

Purpose of Project—The power generated from this project would be: (1) used for municipal water supply pumping; (2) used in Applicant's municipal facilities; and (3) sold to Niagara Mohawk Power Corporation, an investor-owned utility, for eventual distribution to its customers.

Proposed Scope and Cost of Studies Under Permit—Applicant has prepared a hydroelectric feasibility assessment co-sponsored by the U.S. Department of Energy, the New York State Energy Research & Development Authority, and the City of Watervliet. The description and assessment of existing facilities, a preliminary environmental assessment, and a detailed project evaluation review technique (PERT) chart have been completed.

The work proposed under the preliminary permit would include geotechnical investigations, testing, additional land surveys, preparation of maps, plans, and specifications, environmental analysis, and other related activities needed for the preparation of an application for a FERC license. Applicant estimates the cost of the work to be performed under the preliminary permit at $30,000.

Project Description—The proposed project would redevelop the existing City of Watervliet water supply impoundment dam, constructed in 1916, and would consist of: (1) a concrete Ambursen-type dam (crest elevation 259.4 USGS datum) 380 feet long and about 40 feet high with an overflow section approximately 324 feet long surmounted by 3-foot flashboards; (2) a reservoir having a surface area of 430-acres at normal maximum pool elevation 262.4; (3) a new intake structure through the dam; (4) a new 900-foot long, 6-foot-diameter, steel penstock buried in the river bed; (5) a new reinforced-concrete undergorund powerhouse containing a new tube-type turbine-generator rated at approximately 842 kW, and associated equipment; and (6) appurtenant facilities. Applicant estimates that redevelopment would cost $1,747,000 and would provide an average annual generation of 3,568 MW-hours.

Purpose of Preliminary Permit—A preliminary permit does not authorize construction. A permit, if issued, gives the Permittee, during the term of the permit, the right of priority of application for license while the Permittee undertakes the necessary studies and examinations to determine the engineering, economic, and environmental feasibility of the proposed project, the market for the power, and all other necessary information for inclusion in an application for a license. In this instance, Applicant seeks a 12-month permit.

Agency Comments—Federal, State, and local agencies that receive this notice through direct mailing from the Commission are invited to submit comments on the described application for preliminary permit. (A copy of the application may be obtained directly from the Applicant.) Comments should be confined to substantive issues relevant to the issuance of a permit and consistent with the purpose of a permit as described in this notice. No other formal request for comments will be made. If any agency does not file comments within the time set below, it will be presumed to have no comments.

Protests, and Petitions to Intervene—Anyone desiring to be heard or to make any protests about this application should file a petition to intervene or a protest with the Federal Energy Regulatory Commission, in accordance with the requirements of the Commission's Rules of Practice and Procedure, 18 CFR, Section 1.8 or Section 1.10 (1978).

In determining the appropriate action to take, the Commission will consider all protests filed, but a person who merely files a protest does not become a party to the proceeding. To become a party to participate in any hearing, a person must file a petition to intervene in accordance with the Commission's Rules.

Any protest, petition to intervene, or agency comments must be filed on or before December 3, 1979. The Commission's address is: 825 North Capitol Street, N.E., Washington, D.C. 20426.

The application is on file with the Commission and is available for public inspection.

Lois D. Cashell,

Acting Secretary.

[FR Doc. 79-30899 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. ER78-512]

Wisconsin Electric Power Co.; Compliance Filing of New Retail Rate To Service as Ceiling on Wholesale Rate and of Request for Waivers

September 27, 1979.

Take notice that on July 28, 1978, and in response to the Commission's letter order of December 27, 1978, Wisconsin Electric Power Company (WEP) tendered for filing a compliance filing of a new retail industrial rate to serve as the ceiling on a wholesale rate for the two municipal customers of New London and Shawano, Wisconsin. Accompanying this filing were requests for waiver of the Commission's requirement of supporting cost-of-service information and of advance notice of the effectiveness of the rate change promulgated in the filing. WEP requests an effective date for the ceiling of March 15, 1979, which is the effective date set by the Public Service Commission of Wisconsin of the tendered industrial rate for retail service in Wisconsin. If the Commission should not grant the requested effective date of March 15, 1979, WEP requests, in the alternative, an effective date 60 days from the date of this filing.

Any person desiring to be heard or to protest said filing should file a protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 in accordance with Sections 1.8 and 1.10 of the Commission's rules of Practice and Procedure (18 CFR 1.8 and 1.10). All such protests should be filed on or before October 12, 1979. Protest will be considered by the Commission in determining the appropriate action to be taken. Copies of this filing are on file with the Commission and are available for public inspection.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-30900 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

EXECUTIVE OFFICE OF THE PRESIDENT

Office of Administration

Advisory Committee on Information Network Structure and Functions; Meeting

In accordance with the Federal Advisory Committee Act, Pub. L. 92-463, the Office of Administration announces the following meeting:

Name: Advisory Committee on Information Network Structure and Functions.
Date: Tuesday, October 16, 1979.
Time and place: 9 a.m. to 3:30 p.m., room 3104, New Executive Office Building, 17th and Pennsylvania Avenue, N.W., Washington, D.C.
Type of meeting: Open, subject to space limitations. Those wishing to attend must call the contact person below at least 48 hours in advance of the meeting.
Contact person: Frank Brignoli, Advisory Committee Executive Secretary, Office of Administration, Executive Office of the President, Washington, D.C. 20500. Telephone 202-395-4784.

Purpose of advisory committee: The Committee will advise the Director, Office of Administration ("OA"), on matters pertinent to OA's plans for the establishment of a communications network to serve the Executive Office of the President ("EOP"). The Committee will outline a structural and functional plan for the EOP network. This plan will be developed on the basis of current and expected technological developments and will strive for immediate implementation and a minimum useful life of ten years. The plan will address such issues as network hardware and protocol structure, expected structure of servers, gateways and other connections to the network, expected feasible functions, and privacy and authentication mechanisms.

A final report containing the plan is contemplated, and it should provide answers to three questions:

1. What kind of a network should the EOP have?
2. What is it likely to cost?
3. How long is it likely to take to implement?

AGENDA

9 a.m.-12 p.m. Discussion on Information Network Structure and Functions
12 p.m.-1 p.m. Luncheon break
1 p.m.-3:30 p.m. Continued discussion

William R. Pollak,

General Counsel.

[FR Doc. 79-31111 Filed 10-4-79; 9:15 am]

BILLING CODE 3115-01-M

ENVIRONMENTAL PROTECTION AGENCY

Science Advisory Board; Environmental Pollutant Movement and Transformation Committee; Meeting

Under Pub. L. 92-463, notice is hereby given of a meeting of the Environmental Pollutant Movement and Transformation Committee of the Science Advisory Board. The meeting will be held on October 22-23, 1979 in Conference Room 3908 of Waterside Mall, 401 M Street, S.W., Washington, D.C., beginning each date at 9:00 a.m.

The meeting is open to the public. The agenda includes presentations on new organizational relationships and structures in the Office of Research and Development and topics of member interest.

Persons desiring to attend should preregister with the Executive Secretary of the Committee, Dr. Joel L. Fisher. He may be reached at (202) 472-9444. Deadline for preregistration is close of business on October 18, 1979.

Richard M. Dowd,

Staff Director, Science Advisory Board.

October 1, 1979.

[FR Doc. 79-31023 Filed 10-4-79; 8:45 am]

BILLING CODE 6560-01-M

[PF-153; FRL 1334-2]

Pesticide Programs; Filing of Pesticide Petition

Sandoz, Inc., 480 Camino del Rio So., San Diego, CA 92108, has submitted a petition (PP 9F2253) to the Environmental Protection Agency (EPA) which proposes that 40 CFR 180.356 be amended by establishing a tolerance for the combined residues of the herbicide norflurazon (4-chloro-5-(methylamino)-2-

alpha,alpha,alpha-trifluro-*m*-tolyl)-3(2*H*)-pyridazinone and its desmethyl metabolite 4-chloro-5-(amino)-alpha,alpha,alpha-trifluoro-*m*-tolyl)-3(2*H*)-pyridazinone in or on the raw agricultural commodity citrus fruits at 0.2 part per million (ppm). The proposal analytical method for determining residues is gas chromatography using an electron capture detector. Notice of this submission is given pursuant to the provisions of section 408(d)(1) of the Federal Food, Drug, and Cosmetic Act.

Interested persons are invited to submit written comments on this petition. Comments may be submitted, and inquiries directed, to Product Manager (PM) 23, Room E-359, Registration Division (TS-767), Office of Pesticide Programs, EPA, 401 M St., SW, Washington, DC 20460, telephone number 202/755-1397. Written comments should bear a notation indicating the petition number "PP 9F2253". Comments may be made at any time while a petition is pending before the Agency. All written comments filed pursuant to this notice will be available for public inspection in the Product Manager's Office from 8:30 a.m. to 4:00 p.m., Monday through Friday, excluding holidays.

Dated: September 28, 1979.

Douglas D. Campt,

Director, Registration Division.

[FR Doc. 79-31017 Filed 10-4-79; 8:45 am]

BILLING CODE 6560-01-M

[PFT-38; FRL 1333-8]

Pesticide Programs; Filing of Food/Feed Additive Petition

Pursuant to section 409(b)(5) of the Federal Food, Drug, and Cosmetic Act, the Environmental Protection Agency (EPA) gives notice that the following petitions have been submitted to the Agency for consideration.

FAP 9H5238. ICI Americas Inc., Concord Pike & New Murphy Road, Wilmington, DE 19897. Proposes that 21 CFR 193 be amended by permitting the combined residues of the insecticide 2-(dimethylamino)-5,6-dimethyl-4-pyrimidinyl dimethylcarbamate and its metabolites 5,6-dimethyl-2-(formylmethylamino)-4-pyrimidinyl dimethylcarbamate and 5,6-dimethyl-2-(methylamino)-4-pyrimidinyl dimethylcarbamate (both calculated as parent in connection with an experimental program with a tolerance limitation of 0.2 part per million (ppm) in cottonseed oil.

FAP 9H5238. ICI Americas Inc. Proposes that 21 CFR 561 be amended by permitting the combined residues of the above insecticide in connection with an experimental program with tolerance limitations of 2.0 ppm in or on apple pomace and pulp, and cabbage and lettuce wrapper leaves.

Interested persons are invited to submit written comments on these petitions. Comments may be submitted, and inquiries directed to Product Manager (PM) 16, Room E-343, Registration Division (TS-767), Office of Pesticide Programs, EPA, 401 M St., SW, Washington, DC 20460, telephone number 202/426-9458. Written comments should bear a notation indicating the petition number "FAP 9H5238". Comments may be made at any time while a petition is pending before the agency. All written comments filed pursuant to this notice will be available for public inspection in the Product Manager's Office from 8:30 a.m. to 4 p.m., Monday through Friday, excluding holidays.

Dated: September 28, 1979.

Douglas D. Campt,

Director, Registration Division.

[FR Doc. 79-31018 Filed 10-4-79; 8:45 am]

BILLING CODE 6560-01-M

[PF-152; FRL 1334-1]

Pesticide Programs; Filing of Pesticide and Feed Additive Petitions

Pursuant to sections 408(d)(1) and 409(b)(5) of the Federal Food, Drug, and Cosmetic Act, the Environmental Protection Agency (EPA) gives notice that the following petitions have been submitted to the Agency for consideration.

PP 9F2243. FMC Corp., 200 Market St., Philadelphia, PA 19103. Proposes that 40 CFR 180.378 be amended by establishing tolerances for the residues of the insecticide permethrin (3-phenoxyphenyl)methyl (±)-*cis, trans*-3-(2,2-dichloroethenyl)-2,2-dimethylcyclopropanecarboxylate) in or on the following raw agricultural commodities:

Commodity	Part(s) per million
Animal fat	2.0
Lettuce	20.0
Meat, and meat byproducts of cattle, goats, hogs, horses and sheep	0.1
Milk	0.2
Tomatoes	1.0

The proposed analytical method for determining residues is by gas chromatography using an electron capture detector.

FAP 9H5234. FMC Corp. Proposes that 21 CFR 561 be amended by permitting residues of the insecticide permethrin in or on the commodity tomato pomace with a tolerance limitation of 160 ppm.

PP 9F2247. ICI Americas Inc., Concord Pike and New Murphey Road, Wilmington, DE 19897. Proposes that 40 CFR 180.378 be amended by establishing a tolerance for residues of the insecticide permethrin in or on the raw agricultural commodity apples at 2.5 ppm. The proposed analytical method for determining residues is by gas-liquid chromatography using an electron capture detector.

FAP 9H5235. ICI Americas Inc. Proposes that 21 CFR 561 be amended by permitting residues of the insecticide permethrin in or on the commodity dried apple pomace with a tolerance limitation of 65 ppm.

Interested persons are invited to submit written comments on these petitions. Comments may be submitted, and inquiries directed, to Product Manager (PM) 17, Room E-341, Registration Division (TS-767), Office of Pesticide Programs, EPA, 401 M St., SW, Washington, DC 20460, telephone number 202/426-9417. Written comments should bear a notation indicating the petition number to which the comments pertain. Comments may be made at any time while a petition is pending before the Agency. All written comments filed pursuant to this notice will be available for public inspection in the Product Manager's Office from 8:30 a.m. to 4:00 p.m., Monday through Friday, excluding holidays.

Dated: September 28, 1979.

Douglas D. Campt,

Director, Registration Division.

[FR Doc. 79-31019 Filed 10-4-79; 8:45 am]

BILLING CODE 6560-01-M

[FRL 1334-4]

Availability of Environmental Impact Statements

AGENCY: Office of Environmental Review, Environmental Protection Agency.

PURPOSE: This Notice lists the Environmental Impact Statements which have been officially filed with the EPA and distributed to Federal Agencies and interested groups, organizations and individuals for review pursuant to the Council on Environmental Quality's Regulations (40 CFR Part 1506.9).

PERIOD COVERED: This Notice includes EIS's filed during the week of September 24 to September 28, 1979.

REVIEW PERIODS: The 45-day review period for draft EIS's listed in this Notice is calculated from October 5, and will end on November 19, 1979. The 30-day wait period for final EIS's as calculated from October 5, 1979 will end on November 5, 1979.

EIS AVAILABILITY: To obtain a copy of an EIS listed in this Notice you should contact the Federal agency which prepared the EIS. This Notice will give a contact person for each Federal agency which has filed an EIS during the period covered by the Notice. If a Federal agency does not have the EIS available upon request you may contact the Office of Environmental Review, EPA for further information.

BACK COPIES OF EIS'S: Copies of EIS's previously filed with EPA or CEQ which are no longer available from the originating agency are available from the Environmental Law Institute, 1346 Connecticut Avenue, Washington, D.C. 20036.

FOR FURTHER INFORMATION CONTACT: Kathi Weaver Wilson, Office of Environmental Review (A-104), Environmental Protection Agency, 401 M Street, SW, Washington, D.C. 20460 (202) 245-3006.

SUMMARY OF NOTICE: On July 30, 1979, the CEQ Regulations became effective. Pursuant to Section 1506.10(a), the 30 day wait period for final EIS's received during a given week will now be calculated from Friday of the following week. Therefore, for all final EIS's received during the week of September 24 to September 28, 1979, the 30 day wait period will be calculated from October 5, 1979. The wait period will end on November 5, 1979.

Appendix I sets forth a list of EIS's filed with EPA during the week of September 24 to September 28, 1979, the Federal agency filing the EIS, the name, address, and telephone number of the Federal agency contact for copies of the EIS, the filing status of the EIS, the actual date the EIS was filed with EPA, the title of the EIS, the State(s) and County(ies) of the proposed action and a brief summary of the proposed Federal action and the Federal agency EIS number if available. Commenting entities on draft EIS's are listed for final EIS's.

Appendix II sets forth the EIS's which agencies have granted an extended review period or a waiver from the prescribed review period. The Appendix II includes the Federal agency responsible for the EIS, the name, address, and telephone number of the Federal agency contact, the title, State(s) and County(ies) of the EIS, the date EPA announced availability of the EIS in the Federal Register and the extended date for comments.

Appendix III sets forth a list of EIS's which have been withdrawn by a Federal agency.

Appendix IV sets forth a list of EIS retractions concerning previous Notices of Availability which have been made because of procedural noncompliance with NEPA or the CEQ regulations by the originating Federal agencies.

Appendix V sets forth a list of reports or additional supplemental information on previously filed EIS's which have been made available to EPA by Federal agencies.

Appendix VI sets forth official corrections which have been called to EPA's attention.

William N. Hedeman, Jr.,

Director, Office of Environmental Review.

Appendix I—EIS's Filed With EPA During the Week of September 24 to 28, 1979

DEPARTMENT OF AGRICULTURE

Contact: Mr. Barry Flamm, Coordinator, Environmental Quality Activities, Office of the Secretary, U.S. Department of Agriculture, Room 412A, Washington, D.C. 20250 (202) 447-3965.

Soil Conservation Service

Final

Paw-Paw Bottoms RC&D Measure Plan, Sequoyah County, Okla., September 27: Proposed is a RC&D Measure Plan for 4,030 acres of alluvial area within Paw Paw Bottoms located in Sequoyah County Oklahoma. The project plan involves 8.13 miles of channel work and three grade control structures. The channel will be trapezoidal in shape. In addition to no project, two alternatives were considered which consisted of: (1) channel structural measures, and (2) nonstuctural measures including use of higher natural levees for crops, areas with moderate problems for pasture and hayland, and use of severe areas as natural wildlife areas. (USDA-SCS-EIS-RC&D (Adm)-77-3-F-OK). Comments made by: HEW, DOI, DOT, EPA (EIS Order No. 91024).

Rural Electrification Administration

Final

North Dakota-Saskatchewan Intertie, Transmission; Ward, Mountrail, and Burke Counties, N. Dak., September 24: Proposed is the construction of 135 miles of 230 kV alternating current transmission line passing through the Counties of Ward, Mountrail, and Burke, North Dakota. The line will be constructed from Basin Electric's Logan Substation to the Montana-Dakota Utilities' Substation at Tioga, Ward County, to a point on the Canadian border. This project would provide a seasonal interchange of 100 MW of power with Saskatchewan Power Corporation during peak conditions. (USDA-REA-EIS-(ADM) 78-7-F) Comments made by: USDA, DOI, DOT, EPA, COE, State agencies (EIS Order No. 91005).

U.S. ARMY CORPS OF ENGINEERS

Contact: Mr. Richard Makinen, Office of Environmental Policy, Attn: DAEN-CWR-P, Office of the Chief of Engineers, U.S. Army Corps of Engineers, 20 Massachusetts Avenue, Washington, D.C. 20314 (202) 272-0121.

Final

Olcott Small Boat Harbor, Navigation Facilities, Niagara County, N.Y., September 25: Proposed is a Small Boat Harbor plan for the Olcott Harbor located in Niagara County, New York. The plan would provide two breakwaters, one to the west which would protect the existing channel to Eighteenmile Creek and the other on the east which would form a large mooring basin and provide sportfishing. Additional mooring spaces would be supplied by the west breakwater. Several new channels will be incorporated with limited dredging which would be disposed of at an upland site. Recreational facilities will be included. (Buffalo District) Comments made by: AHP, HEW, DOC, DOI, HUD, DOT, EPA, State and local agencies (EIS Order No. 91010).

Deepwater Port and Crude Oil System, Permit, Galveston County, Tex., September 27: Proposed is the issuance of a permit for an onshore deepwater port project which would involve the deepening of the existing ship channel into Galveston, Galveston County, Texas and extending the channel further into the Gulf of Mexico. Also proposed is the construction of a crude oil pipeline distribution system, originating at Pelican Island, and an oil storage tank farm. Several disposal sites will be used, dependent upon the type of dredged material. (Galveston District) Comments made by: EPA, DOI, DOC, AHP, USDA, HUD, DOT, State and local agencies, businesses (EIS Order No. 91020).

Draft Supplement

Manteo (Shallowbag) Bay Project (DS-1), Dare County, N.C., September 26: This statement supplements a final EIS, #90384, filed 4-11-79 concerning the Manteo (Shallowbag) Bay Project located in Dare County, North Carolina. This supplement discusses: 1) dredged material by controlled effluent rather than diked upland disposal, 2) elimination of the jetty doors, and 3) dredging the Oregon Inlet ocean bar channel by hydraulic pipeline dredge during project construction. Other changes, omissions of the final EIS and additional information to the final EIS are presented. (Wilmington District) (EIS Order No. 91015).

DEPARTMENT OF COMMERCE

Contact: Dr. Sidney R. Galler, Deputy Assistant Secretary, Environmental Affairs, Department of Commerce, Washington, D.C. 20230 (202) 377-4335.

National Oceanic and Atmospheric Administration

Final Supplement

Atlantic Herring FMP, Amendment (FS-1), Regulatory, Atlantic Ocean, September 27: This statement supplements final EIS, #81013, filed 9-19-78 on the Atlantic Herring FMP. Proposed is an amendment to: 1) redefine the management unit to include all herring fisheries, 2) establish new optimum yields for the Gulf of Maine and Georges Bank and south areas including an allocation of 2,000 MT to Canada from Georges Bank, 3) make suballocations of the Gulf of Maine optimum yield to reflect seasonal activity of historic fisheries, 4) establish new area/period allocations of harvests of all Herring three years and older, and 5) provide a definition of industry guidance of Herring age three years and older. Comments made by: Businesses (EIS Order No. 91022).

To fulfill the minimum 90 day requirement the period of review for the above final supplement EIS will extend to November 7, 1979. See Appendix II.

DEPARTMENT OF DEFENSE, ARMY

Contact: Col. Charles E. Sell, Chief of the Environmental Office, Headquarters DAEN-ZCE, Office of the Assistant Chief of Engineers, Department of the Army, Room 1E676, Pentagon, Washington, D.C. 20310 (202) 694-4269.

Draft

Fort McPerson and Subinstallations (continuation), Charlie Brown County, September 28: Proposed is the continuation of existing activities at Fort McPerson located in Charlie Brown County, Georgia and its subinstallations of Fort Gillem, the FORSCOM Flight Detachment at Charlie Brown County Airport, and the FORSCOM Recreation Area at Lake Allatoona. Activities include support of: FORSCOM, various military and nonmilitary organizations and to almost 17,000 military retirees and 34,000 dependents, and warehouse storage facilities. (EIS Order No. 91027).

DEPARTMENT OF DEFENSE, NAVY

Contact: Mr. Ed Johnson, Head, Environmental Impact Statement/RDT&E Branch, Office of the Chief of Naval Operations, Department of the Navy, Washington, D.C. 20350 (202) 697-3689.

Draft

Wharf Construction, Access Dredging and Disposal, Chesapeake County, Va., September 26: Proposed is the construction of a 690 foot ammunition-handling wharf to be located on the southeastern shore of Little Creek Cove, Naval Amphibious Base, Little Creek, Virginia. Associated access dredging of a channel 700 feet long to a depth of 20 feet plus 2 feet overdepth below mean low water leading to the proposed wharf. Also addressed in this proposal is the building of a causeway behind the wharf in order to support vehicular traffic to and from the area and depositing dredged material in a diked area approximately 50 yards behind the wharf on lands within the jurisdiction of the Naval Amphibious Base. (EIS Order No. 91014).

ENVIRONMENTAL PROTECTION AGENCY

EPA, Headquarters

Contact: Mr. Fred Mintz, program Manager, Truck-Mounted Solid Waste Compactors, Office of Noise Abatement and Control (ANR-490), U.S. Environmental Protection Agency, Washington, D.C. 20460 (703) 557-2710.

Final

Truck-Mounted Solid Waste Compactors, Noise, Regulatory, September 27: Proposed is the establishment of noise emission standards for newly manufactured compactors and procedures to ensure that this equipment complies with the standard. The proposed regulation is intended to reduce the level of noise emitted from truck mounted solid waste compactors used in collecting solid wastes. The regulation is also intended to establish a uniform national standard for this equipment distributed in commerce, thereby eliminating inconsistent state and local noise source emission regulations that may impose an undue burden on the truck solid waste compactor industry. Comments made by: (EIS Order No. 91030).

DEPARTMENT OF ENERGY

Contact: Dr. Robert Stern, Acting Director, NEPA Affairs Division, Department of Energy, Mail Station 4G-064, Forrestal Bldg., Washington, DC 20585 (202) 252-4600.

Final

Coal Conversion Program, Brayton Point, Bristol County, Mass., September 27: Proposed is a Notice of Effectiveness to prohibit burning of gas or oil as the primary source of fuel at New England Power Company's Brayton Point Generating Station, Somerset, Bristol County, Massachusetts, for Units 1, 2, and 3. The Notice of Effectiveness would make effective the June 30, 1977 Energy Supply and Environmental Coordination Act Prohibition Order issued by FEA. The alternatives considered include: 1) fuel mix, 2) alternate fuels, 3) early retirement, 4) no action. (DOE/EIS-0036-F). Comments made by: USDA, COE, DOE, HEW, HUD, DOI, STAT, DOT, TREA, EPA, NSF, State agencies, groups, individuals and businesses (EIS Order No. 91025).

Bonneville Power Administration

Final Supplement

Southwest Oregon Area Service, Facility Plan (fiscal year 1979)., Several Counties, Oregon and Idaho, September 24: Proposed is the facility planning supplement to the FY 1979 program for the Southwest Oregon Service Area to allow power generated in Wyoming to be delivered and to facilitate the exchange of electric power between the Pacific Northwest and the Middle Snake Region, Construction of two transmission facilities proposed includes: 1) 500 KV line from Brownlee Substation in Idaho to Slatt Substation near Arlington, Oregon and 2) 500 KV line from Buckley to Malin, Oregon. The new transmission line would provide backup to the overall system. (DOE-EIS-0005-FS-2). Comments made by: DOI, DOT, COE, EPA, USDA, State and local agencies, individuals and businesses (EIS Order No. 91004).

GENERAL SERVICES ADMINISTRATION

Contact: Mr. Carl W. Penland, Acting Director, Environmental Affairs Division, General Services Administration, 18th and F Streets, N.W., Washington, D.C. 20405 (202) 566-1416.

Final

Federal Office Building, Providence, Providence County, R.I., September 24: This action proposes the lease construction of a Federal Office Building in Providence, Rhode Island. The new Federal Office Building will provide modern, efficient, consolidated housing for the Veterans Administration Regional Office, the Department of the Treasury, and Health, Education, and Welfare, and several other agencies now housed at various scattered locations in the Providence Area. The new building will provide approximately 129,000 square feet of agency office space, to house approximately 580 employees. Additionally, parking will be provided for 40 Government-owned vehicles. (ERI 78-001). Comments made by: EPA, HUD, DOI, SBA, State and local agencies (EIS Order No. 91006).

DEPARTMENT OF THE INTERIOR

Contact: Mr. Bruce Blanchard, Director, Environmental Project Review, Room 4256 Interior Bldg., Department of the Interior, Washington, D.C. 20240, (202) 343-3891.

Bureau of Land Management

Draft

Crossman Peak Radar Installation, Mohave County, Ariz., September 24: Proposed is the construction of Air Surveillance Radar facilities either on Crossman Peak, near Lake Havasu City in Mohave County, Arizona or at two other sites in Arizona: 1) on Cherum Peak, Mohave County, or 2) Harquahula Peak, Yuma County. The facilities would provide low-elevation air traffic coverage in the Lower Colorado River Basin, presently lacking such coverage, and high-elevation air traffic coverage, within a 100-mile radius of Kingman, Arizona. The roads needed to provide access to any of the summits would improve access for recreation and mining. (DES-79-54) (EIS Order No. 91002).

1980 OCS Sale Nos. 62A and 62, Gulf of Mexico, September 28: Proposed are two 1980 OCS oil and gas lease sales, Nos. 62A and 62, in the Gulf of Mexico. The sales would include 296 tracts totaling 1,517,787.37 acres. Sale 62A includes 222 tracts totaling 1,099,057.37 acres ranging from 3 to 104 nautical miles from shore in water from 12 to 2,179 feet deep. Sale 62 includes 74 tracts offshore the Western Gulf of Mexico totaling 418,730 acres ranging from 11 to 99 nautical miles offshore in waters from 30 to 1,460 feet deep. (EIS Order No. 91029).

Final

Vermillion Resource Area Livestock Grazing Program, Coconino and Mohave Counties, September 26: Proposed is a livestock grazing program for the Vermillion resource area located in the Counties of Coconino and Mohave, Arizona. The area consists of 1,407,476 acres of federal lands. The program includes: 1) intensive management of grazing on 1,369,043 acres of land, 2) less intensive management of grazing on 38,433 acres, and 3) building range improvements and applying land treatments to facilitate grazing management. Four alternatives are considered. Comments made by: DOI, EPA, State agencies, groups, individuals and businesses (EIS Order No. 91011).

East Roswell Grazing Management Program, Chaves, Lea, and Eddy Counties, N. Mex., September 27: Proposed is the implementation of a livestock grazing management program for the East Roswell area located in Chaves, Lea and Eddy Counties, New Mexico. The plan would: exclude approximately 6,600 acres from livestock grazing; allocate 168,111 AUMs of forage to livestock and 2,893 AUMs to big game animals; set a maximum forage utilization-level of 40 to 60 percent; treat approximately 54,300 acres with chemicals to control brush; develop grazing management systems; and specify livestock facilities necessary to implement systems. (FES-79-49). Comments made by: AHP, USDA, COE, DOI, EPA, State and local agencies, groups, individuals and businesses (EIS Order No. 91021).

Final

Randolph Planning Unit Grazing Management Plan, Rich County, Utah, September 27: Proposed are livestock grazing management plans for the Randolph Planning Unit in Rich County, Utah. The purpose is to provide for the 140,298 acres, sustained, long term, productive use of natural resources which will be accomplished in two phases. The first phase includes: allocation of 22,350 AUMs of livestock forage on 19 allotments; allotment-wide continuous grazing authorized on 15 allotments; and unchanged grazing management on 4 allotments. The second phase includes an increase of livestock forage on a sustained basis to 35,241 AUMs and long term management consisting of livestock grazing, vegetation treatments, fences, water developments, and cattleguards. (FES-79-48). Comments made by: DOI, USDA, EPA, COE, State and local agencies groups (EIS Order No. 91023).

Final

Parker Mountain Planning Unit Grazing Management, Wayne County, Utah, September 28: Proposed is a grazing management plan for the Parker Mountain Planning Unit located in Wayne County, Utah. The Unit encompasses 213,057 acres of public land and will be allocated with the following AUMs: 1) 11,180 for livestock, 2) 1,927 for deer, 3) 406 for elk, and 4) 617 for antelope. The action would: 1) reserve two allotments for big game use, 2) continue existing grazing on 15 allotments, 3) combine five allotments and implement rest seasonal grazing, 4) reduce grazing use by approximately 56% (1,431 AUMs) on 20 allotments, and 5) change season of use on one allotment. (FES-79-50). Comments made by: USDA, DOI, EPA, State and local agencies, individuals (EIS Order No. 91026).

Geological Survey

Final

Big Sky Mine Expansion and Reclamation Plan, Rosebud County, Mont., September 25: Proposed is an expansion/reclamation plan for the Big Sky Mine, Peabody Coal Company, Rosebud County, Montana. The company proposes to expand the existing plant and loading facilities, haul and access roads, and utilize the existing rail spur extending from Colstrip. An estimated 30 million tons of low-sulfur coal would be removed from an area of about 894 acres over a period of about 8 years. (FES-79-48). Comments made by: AHP, USDA, HEW, DOI, DLAB, EPA, State agencies, businesses (EIS Order No. 91009).

National Park Service

Draft

Redwood National Park, General Management Plan, Del Norte and Humboldt Counties, Calif., September 25: Proposed is the general management plan for Redwood National Park located in Del Norte and Humboldt Counties, California. The Park encompasses approximately 106,000 acres, of which about 25 percent are within three California state parks. The plan contains the visitor use and facility development plan, the cultural resources management plan, and major goals and actions related to natural resources management and rehabilitation. Four alternatives have been discussed with the preferred alternative combining the no action, extended visit, and the restructured visitor use alternatives. (DES-79-55) (EIS Order No. 91013).

Final

Gateway National Recreation Area, Master Plan, New York and New Jersey, September 25: Proposed is the general management plan implementation for Gateway National Recreation Area located in New York and New Jersey to guide overall park management and development for approximately 20 years, as well as specific development concept plan implementation for about 7 years. The National Park Service at present administers some 89 percent of the 8,373 acres of land that will be open for public use when all lands to be donated, acquired, or transferred as part of the ongoing land acquisition program have been placed under its jurisdiction. Another 1,241 acres of land will remain under other jurisdiction either as enclave properties or as right-of-way. (FES-79-45). Comments made by: AHP, EPA, GSA, COE, DOC, DOE, HEW, HUD, DOI, DLAB, DOT, State and local agencies (EIS Order No. 91008).

DEPARTMENT OF TRANSPORTATION

Contact: Mr. Martin Convisser, Director, Office of Environmental Affairs, U.S. Department of Transportation, 400 7th Street, S.W., Washington, D.C. 20590, (202) 426-4357.

Federal Highway Administration

Draft

Tenth Street/Taylor Road Extension, Columbus, Bartholomew County, Ind., September 27: Proposed is the extension of Tenth Street northeast from US 31 to IN-46 and the extension of Taylor Road from IN-46 to Marr Road located in Columbus, Bartholomew County, Indiana. The partially access controlled roads would be generally 2-lane pavements, with a 4-lane connector between US 31 and Taylor Road. Right of way requirements vary from approximately 100 to 140 feet. The Tenth Street extension study lines are 0.95 to 1.67 miles long. The Taylor Road study lines are 1.25 to 1.59 miles long. (FHWA-IND-EIS-78-06-D) (EIS Order No. 91016).

I-59/US 84, Laurel Bypass, Jones County, Miss., September 27: Proposed is the relocation of I-59 and US 84 corridors in Laurel, Jones County, Mississippi. In addition to no-build four other corridor alternatives are considered. The termini, type of highway, number of lanes, and length varies according to the alternate. (FHWA-MS-EIS-79-01-D) (EIS Order No. 91017).

US 10A, West Valley Highway-Anaconda, Deer Lodge County, Mont., September 24: Proposed is the reconstruction of a portion of US 10A, the West Valley Highway in Deer Lodge County, Montana. The project begins 4.5 miles west of Anaconda at I-90 and extends east to I-90 at Anaconda. Four alternatives are considered: 1) a four-lane road on the present alignment with a 16 foot median and bike path-sidewalk, 2) a two-lane road on present alignment with bike path-sidewalk and a frontage road, 3) a two-lane road south of the present road, and 4) no action. The length of the project is 4.5 miles. (FHWA-MONT-EIS-79-01-D) (EIS Order No. 91003).

Final

I-75 Improvement, Cleveland and Central Avenues, Fulton and Clayton Counties, Ga., September 27: Proposed are two concurrent projects which involve the widening and improvement of I-75, beginning at I-285 and following I-75 northward to the interchange area at the Lakewood Freeway in Clayton and Fulton Counties, Georgia. Also included will be interchange improvements at Central Avenue and Cleveland Avenue, with an interchange to be added to serve Hartsfield International Airport. The facility will be limited access. In addition to no-build, two alternatives are considered. (EIS-GA-EIS-78-01-F). Comments made by: EPA, HUD, DOI, HEW, FERC, State and local agencies (EIS Order No. 91019).

NY-31 Improvement, Onondaga County, N.Y., September 24: Proposed is the improvement of NY-31 from NY-690 and NY-481 in Onondaga County, New York. The facility would be a four-lane, limited highway. The alternatives considered include: 1) no action, 2) build road along existing NY-31, 3) start north of Baldwinsville at I-690 through Radisson to NY-481, 4) start south of Baldwinsville at I-690 through Radisson to NY-481, 5) two alternatives starting south of Baldwinsville proceeding north to and along NY-31 to NY-481, and 6) start south of Baldwinsville at NY-690 and proceed east and south to NY-481. (FHWA-NY-EIS-74-06-F). Comments made by: USDA, COE, DOC, HEW, DOI, DOT, EPA, State and local agencies, businesses (EIS Order No. 91007).

Final

I-93 and US 1 Interchange, Boston and Cambridge, Suffolk County, Mass., September 17: Proposed is the reconstruction of the I-93/US 1 Interchange located in the Charleston section of the City of Boston, Suffolk County, Massachusetts. Improvements will include straightening the S-curve at the foot of the Mystic Bridge, construction of two tunnels under City Square, two new loop ramps to connect to I-93, removing existing elevated expressway ramps over City Square, and improving vehicular and pedestrian circulation in City Square and adjacent surface streets. Three alternatives were considered. (FHWA-MASS-EIS-77-01-F).

Comments made by: DOI, DOC, DOT, COE, EPA, HUD, USDA, State and local agencies, groups and businesses (EIS Order No. 90604).

The above final EIS was refiled on September 17, 1979 and omitted from the September 28, 1979 Federal Register Notice. See Appendix VI.

Supplement

I-69, US 127 to Existing I-69, Morrice, Clinton and Shiawassee Counties, Mich., September 28: This statement supplements a draft EIS, #40025, filed 1-3-74, concerning the construction of I-69 from US 127 to existing I-69 in Clinton and Shiawassee, Michigan. This supplement discusses: 1) consideration of alternates 2W, 3W, and 1W, which pass south of Park Lake; 2) the addition of an interchange site at Woodbury Road and deletion of the formerly proposed Shaftsburg Road interchange; 3) selection of a new preferred alignment which avoids Section 4(f) involvement. (FHWA-MICH-EIS-73-06-DS) (EIS Order No. 91028).

EIS's Filed During the Week of September 24 to 28, 1979

[Statement Title Index—by State and County]

State	County	Status	Statement title	Accession No.	Date filed	Orig. Agency No.
Atlantic Ocean		F Suppl	Atlantic Herring FMP, Amendment	91022	09-27-79	DOC.
Arizona	Coconino	Final	Vermillion Resource Area Livestock Grazing Program.	91011	09-26-79	DOI.
	Mohave	Draft	Crossman Peak Radar Installation	91002	09-24-79	DOI.
		Final	Vermillion Resource Area Livestock Grazing Program.	91011	09-26-79	DOI.
California	Del Norte	Draft	Redwood National Park, General Management Plan	91013	09-25-79	DOI.
	Humboldt	Draft	Redwood National Park, General Management Plan	91013	09-25-79	DOI.
Georgia	Charlie Brown	Draft	Fort McPherson and Subinstallations, continuation	91027	09-28-79	USA.
	Clayton	Final	I-75 Improvement, Cleveland & Central Avenues	91019	09-27-79	DOT.
	Fulton	Final	I-75 Improvement, Cleveland & Central Avenues	91019	09-27-79	DOT.
Gulf of Mexico		Draft	1980 OCS Nos. 62A and 62, Gulf of Mexico	91029	09-28-79	DOI.
Idaho	Several	F Suppl	Southwest Oregon Area Service, Facility Plan FY 79.	91004	09-24-79	DOE.
Indiana	Bartholomew	Draft	Tenth Street/Taylor Road Extension, Columbus	91016	09-27-79	DOT.
	Suffolk	Final	I-93 & US 1 Interchange, Boston & Cambridge	90604	09-17-79	DOT.
Massachusetts	Bristol	Final	Coal Conversion Program, Brayton Point	91025	09-27-79	DOE.
Michigan	Clinton	Supple	I-69, US 127 to existing I-69, Morrice	91028	09-28-79	DOT.
	Shiawassee	Supple	I-69, US 127 to existing I-69, Morrice	91028	09-28-79	DOT.
Mississippi	Jones	Draft	I-59/US 84, Laurel Bypass	91017	09-27-79	DOT.
Montana	Deer Lodge	Draft	US 10A, West Valley Highway-Anaconda	91003	09-24-79	DOT.
	Rosebud	Final	Big Sky Mine Expansion and Reclamation Plan	91009	09-25-79	DOI.
New Jersey		Final	Gateway National Recreation Area, Master Plan	91008	09-25-79	DOI.
New Mexico	Chaves	Final	East Roswell Grazing Management Program	91021	09-27-79	DOI.
	Eddy	Final	East Roswell Grazing Management Program	91021	09-27-79	DOI.
	Lea	Final	East Roswell Grazing Management Program	91021	09-27-79	DOI.
New York		Final	Gateway National Recreation Area, Master Plan	91008	09-25-79	DOI.
	Niagara	Final	Olcott Small Boat Harbor, Navigation Facilities	91010	09-25-79	COE.
	Onondaga	Final	Route 31 Improvement	91007	09-24-79	DOT.
North Carolina	Dare	Supple	Manteo (Shallowbag) Bay Project (DS-1)	91015	09-26-79	COE.
North Dakota	Burke	Final	North Dakota-Saskatchewan Intertie, Transmission	91005	09-24-79	USDA.
	Mountrail	Final	North Dakota-Saskatchewan Intertie, Transmission	91005	09-24-79	USDA.
	Ward	Final	North Dakota-Saskatchewan Intertie, Transmission	91005	09-24-79	USDA.
Oklahoma	Sequoyah	Final	Paw-Paw Bottoms RC&D Measure Plan	91024	09-27-79	USDA.
Oregon	Several	F Suppl	Southwest Area Service, Facility Plan FY 79	91004	09-27-79	DOE.
Regulatory		F Suppl	Atlantic Herring FMP, Amendment (FS-1)	91022	09-27-79	DOC.
		Final	Truck-Mounted Solid Waste Compactors, Noise	91030	09-27-79	EPA.
Rhode Island	Providence	Final	Federal Office Building, Providence	91006	09-24-79	GSA.
Texas	Galveston	Final	Deepwater Port and Crude Oil System, Permit	91020	09-27-79	COE.
Utah	Rich	Final	Randolph Planning Unit Grazing Management Plan.	91023	09-27-79	DOI.
	Wayne	Final	Parker Mtn. Planning Unit Grazing Management	91026	09-27-79	DOI.
Virginia	Chesapeake	Draft	Wharf Construction, Access Dredging and Disposal.	91014	09-26-79	USN.
Wisconsin	Dane	Final	Capitol Centre Redevelopment, Madison	91018	09-27-79	HUD.

Appendix II.—*Extension/Waiver of Review Periods on EIS's Filed With EPA*

Federal agency contact	Title of EIS	Filing status/accession No.	Date notice of availability published in "Federal Register"	Waiver/ extension	Date review terminates
Department of Commerce					
Dr. Sidney R. Galler, Deputy Assistant Secretary, Environmental Affairs, Department of Commerce, Washington, D.C. 20230 (202) 377-4335.	Atlantic Herring FMP, amendment	Final Supplement 91022	October 5, 1979 (see appendix I).	Extension	November 7, 1979.
Department of Defense, Air Force					
Dr. Carlos Stern, Deputy for Environment and Safety, Department of the Air Force, Room 4C885, Pentagon, Washington, D.C. 20330 (202) 697-9297.	Holloman AFB, Morenci Area, Supersonic Operations, Carton County, New Mexico.	Final 90797	August 3, 1979	Extension	October 16, 1979.

Appendix III.—*EIS's Filed With EPA Which Have Been Officially Withdrawn by the Originating Agency*

Federal agency contact	Title of EIS	Filing status/accession No.	Date notice of availability published in "Federal Register"	Date of withdrawal
None.				

Appendix IV.—*Notice of Official Retraction*

Federal agency contact	Title of EIS	Status/number	Date notice published in "Federal Register"	Reason for retraction
None.				

Appendix V.—*Availability of Reports/Additional Information Relating to EIS's Previously Filed With EPA*

Federal agency contact	Title of report	Date made available to EPA	Accession No.
None.			

Appendix VI.—*Official Correction*

Federal agency contact	Title of EIS	Filing status/ accession No.	Date notice of availability published in "Federal Register"	Correction
DEPARTMENT OF TRANSPORTATION				
Mr. Martin Convisser, Director, Office of Environmental Affairs, U.S. Department of Transportation, 400 4th Street, S.W., Washington, D.C. 20590 (202) 426-4357.	I-93 and US 1 Interchange, Boston and Cambridge, Suffolk County, Massachusetts.	Final 90604	October 5, 1979 (see appendix I).	This final EIS had been retracted and was refiled on September 17, 1979. It was omitted from the September 28, 1979 FEDERAL REGISTER Notice. The review period began on September 28, 1979 and will end on October 5, 1979.

In the FEDERAL REGISTER Notice dated September 21, 1979, Appendix V listed an NRC document entitled, "Decommissioning Commercial Nuclear Facilities: A Review and Analysis of Current Regulations," as Report No. 90954. This document was not a report relating to a previously filed EIS and was listed in error.

[FR Doc. 79-31020 Filed 10-04-79; 8:45 am]

BILLING CODE 6560-01-M

[OTS-51003; FRL 1334—]

Premanufacture Notice

AGENCY: Environmental Protection Agency (EPA, or the Agency).

ACTION: Receipt of Premanufacture Notice.

SUMMARY: Section 5(a)(1)(A) of the Toxic Substances Control Act (TSCA) requires any person who intends to manufacture or import a new chemical substance to submit a premanufacture notice (PMN) to EPA at least 90 days before manufacture or import. Section 5(d)(2) requires EPA to publish a summary of each PMN in the Federal Register. This Notice announces receipt of a PMN and provides a summary.

DATE: Persons who wish to file written comments on a specific chemical substance should submit their comments no later than 30 days before the applicable notice review period ends.

ADDRESS: Written comments should bear the PMN number of the particular chemical substance, and should be submitted in triplicate, if possible, to the Document Control Officer (TS-793), Office of Toxic Substances, EPA, 401 M Street, S.W., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Mr. Kirk Maconaughey, Premanufacturing Review Division (TS-794), Office of Toxic Substances, EPA, Washington, D.C. 20460, telephone: 202/426-2601.

SUPPLEMENTARY INFORMATION: Under section 5 of TSCA, any person who intends to manufacture or import a new chemical substance must submit a premanufacture notice (PMN) to EPA at least 90 days before manufacture or import. A "new" chemical substance is any substance that is not on the Inventory of existing substances compiled by EPA under section 8(b) of TSCA. On May 15, 1979, EPA announced the availability of the Initial Inventory and identified June 1, 1979, as the official publication date (44 FR 28559). The section 5 requirements became effective on July 1, 1979.

A PMN must include the information listed in section 5(d)(1) of TSCA. Under section 5(d)(2) subject to section 14, EPA must publish in the Federal Register information on the identity and uses of the substance, as well as a description of any test data submitted under section 5(b). In addition, EPA has decided that the section 5(d)(2) notice will include a description of any other test data submitted with the PMN, plus the identity of the manufacturer, when possible.

Publication of the section 5(d)(2) notice is subject to section 14 concerning disclosure of confidential data. A company can claim confidentiality for any information submitted as part of a PMN. If the company claims confidentiality for the specific chemical identity, EPA will publish a generic name if the submitter provides one. If no generic name is provided, EPA will develop one and publish an amended notice after providing due notice to the submitter. EPA immediately will review confidentiality claims for chemical identity and for health and safety studies. If EPA determines that portions of this information are not entitled to confidential treatment, after complying with applicable procedures, the Agency will place the information in the public file and will publish an amended notice of the information that should have been in the original Federal Register notice.

Once EPA receives a PMN, the Agency normally has 90 days to review it (section 5(a)(1)). The section 5(d)(2) Federal Register notice indicates the date when the review period ends for each PMN. Under section 5(c), EPA may for good cause extend the review period for up to an additional 90 days. If EPA determines that an extension is necessary, it will publish a notice in the Federal Register.

Once the review period ends, the submitter may manufacture the substance unless EPA has imposed restrictions. When manufacture begins, the submitter must report to EPA and the Agency will add the substance to the Inventory. After the substance is added to the Inventory, anyone may manufacture it without providing EPA notice under section 5(a)(1)(A).

EPA has proposed Premanufacture Notification Requirements and Review Procedures (44 FR 2242, January 10, 1979). These requirements are not yet in effect. Interested persons should consult the Agency's Interim Policy (44 FR 28564, May 15, 1979) for guidance concerning premanufacturing requirements prior to the effective date of the premanufacture rules and forms. In particular, see the section entitled "Notice in the Federal Register" on p. 28567 of the Interim Policy.

Authority: Section 5 of the Toxic Substances Control Act (90 Stat. 2012; 15 U.S.C. 2604).

Dated: October 20, 1979.

John P. DeKany,

Deputy Assistant Administrator for Chemical Control.

PMN No. 5AHQ–0979–0011(A)

Close of Review Period: December 23, 1979.

Manufacturer's Identity: The submitter has claimed as confidential the company's name.

New Chemical Substance: The chemical identity of the substance is poly (vinyl acetate, acrylic acid, butyl acrylate, dioctyl maleate, 2-ethylhexyl acrylate).

Uses: The substance is intended to be used as an adhesive able to replace either a water-based or a solvent-based adhesive. In its dried condition it is similar to the adhesive backing on cellophane tape. The company anticipates that for the first three calendar years 4,000 pounds, 20,000 pounds, and 40,000 pounds, respectively, will be produced for this use. The company has also submitted the following information on estimated worker exposure at the manufacturing site:

Route	Number of exposed employees	Maximum duration of exposure
Inhalation (monomers)	2	20 hrs/yr.
Dermal (finished latex product).	3	100 hrs/yr.

The company reports that the maximum total monomer vapor concentration at the site is 5 ppm and is usually less than 1–2 ppm.

Data Submitted: The company submitted the following data concerning physical and chemical properties for both the emulsion and the dried product:

	Emulsion	Dried Product
Solids content	54.5 to 56.5 percent	100 percent.
Viscosity	200 to 600 cps	Not applicable.
pH	4.0 to 5.0	Not applicable.
Specific gravity	1.04	1.07.
Boiling point	210°C	None.
Vapor pressure	21 mm Hg	None.
Particle size	0.05 to 0.5 microns (estimated).	Not applicable.
Solubility:		
In water	Forms dispersion in water	1.4.
In acetone	Coagulates	Partially soluble.
Molecular weight	10^5 to 10^6 (est.)	10^5 to 10^6 (est.).
Hydrolysis	Slight	Slight.
Photochemical degradation	Slight	Slight.
Chemical oxidation	Very slight	Very slight.
Chemical incompatibility	None	None.
Flammability	Non-flammable	combustible.
Explodability	None	None.
Flash point	None	None.
Biodegradability	Very slow	Very slow.

The company also submitted the following health and environmental information on each of the monomers:

Vinyl Acetate: Vinyl acetate monomer is considered a chemical of low toxicity, and has no known important health hazards, no systemic effects, and no chronic effects or sensitizations at relatively low levels of exposure. (TLV—10 ppm)

In atmospheric exposure of Sprague-Dawley rats to 2,500 ppm vinyl acetate four hours daily, five days a week, for 12 months, no liver angiosarcomas were observed.

Dioctyl Maleate

Oral LD_{50} based on rats is 14 gm/kg.

Skin sensitivity MLD based on rabbits is 15 gm/kg.

Butyl Acrylate

Single oral LD_{50} based on rats is 3.73 gm/kg.

Single skin penetration, LD_{50}, rabbits, is 3.36 ml/kg.

Single inhalation, concentrated vapor, rats: 30 min. killed none of 6; 1 hr. killed 5 of 6.

Primary skin irritation, rabbits—trace.

Eye injury, rabbits—minor.

2-Ethylhexyl Acrylate

Single oral LD_{50} based on rats is 5.66 gm/kg.

Single skin penetration, LD_{50}, rabbits, is 8.5 ml/kg.

Single inhalation, concentrated vapor, rats: 8 hrs. killed none of 6.

Primary skin irritation, rabbit—moderate.

Eye injury, rabbits—trace.

Repeated skin exposure of mice to a solution of 2-ethylhexyl acrylate in acetone over the lifetime of the animals. The animals were treated 3 times per week. After 21 months, 3 mice out of 31 developed benign skin tumors. No skin tumors were found on control animals treated only with acetone. The study is still in progress.

Acrylic Acid

Single oral LD_{50} based on rats in 2.50 g/kg.

Single skin penetration, LD_{50}, rabbits, is 0.95 ml/kg.

Single inhalation, concentrated vapor, rats: 8 hrs. killed none of 6.

The report on which data are based and other nonconfidential information concerning this notice is available in the public record in the Office of Toxic Substances Reading Room from 9:00 a.m. to 5:00 p.m. on working days (Room E-447, 401 M Street, S.W., Washington, D.C. 20460.

[FR Doc. 79-31014 Filed 10-4-79; 8:45 am]

BILLING CODE 6560-01-M

[OTS-50006; FRL 1334-5]

Transfer of TSCA Premanufacture Notification Information to Contractor; Data Transfer

AGENCY: Environmental Protection Agency (EPA), Office of Toxic Substances.

ACTION: Notice of Data Transfer.

SUMMARY: EPA will transfer information contained in Premanufacture Notices (PMN's) submitted by manufacturers and importers under Section 5 of the Toxic Substances Control Act (TSCA) to its contractor, MITRE Corporation (Metrek Division) of McLean, Virginia. Some of this information may be claimed to be confidential. MITRE will review, analyze, and report to EPA on manufacturing and processing methods, chemical use, exposure, and environmental release information contained in PMN's.

DATE: The transfer of data submitted in PMN's and claimed to be confidential will occur no sooner than 10 working days after publication of this notice in the Federal Register.

FOR FURTHER INFORMATION CONTACT: Mr. John B. Ritch, Jr., Director, Industry Assistance Office, Office of Toxic Substances (TS-799), Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460. The toll-free telephone number is 800/424-9065. In Washington, D.C., please call 554-1404.

SUPPLEMENTARY INFORMATION: Under Section 5 of TSCA, manufacturers and importers of chemical substances are required to submit PMN's for new chemical substances that they intend to manufacture or import and that are not included in EPA's Initial Inventory of Chemical Substances. To evaluate the information in these PMN's, EPA will require the assistance of outside experts. EPA has selected MITRE Corporation (Metrek Division), McLean, Virginia, to assist it in evaluating potential risks associated with the manufacture, processing, distribution in commerce, use, and disposal of new chemical substances (Contract No. 68-01-5863).

Pursuant to 40 CFR 2.306(j), EPA has determined that it will need to disclose confidential busniess information to MITRE. Under the terms of the contract, EPA will provide MITRE with information submitted in PMN's on chemical identity, product formulation, and specific processes used to manufacture or process new chemical substances, as well as other information related to the uses, release rates, and exposure levels of new chemical substances. If any PMN information is claimed to be confidential, reports prepared by MITRE dealing with this Confidential Business Information will be treated as confidential. After evaluating the information in a PMN, MITRE will retrun the PMN and any reports prepared by MITRE to EPA.

Since MITRE will review information claimed to be confidential, EPA is publishing this Notice to inform all submitters of PMN's that MITRE will receive Confidential Business Information from EPA.

MITRE is legally required under the terms of its contract not to reveal to anyone outside its organization the fact that EPA has requested a review of any PMN submission. MITRE also is legally required to safeguard from any unauthorized disclosure the PMN's and any information generated during MITRE's review. MITRE's contract specifically prohibits disclosure of any of this information to any third party in any form without written authorization from EPA.

MITRE has been authorized under the EPA TSCA Confidential Business Information Security Manual to have access to Confidential Business Information. EPA has approved MITRE's security plan. EPA's Security and Inspection Division has conducted the required inspection of the MITRE (Metrek Division) facilities and has found them to be in compliance with the requirements of the Security Manual. MITRE is required to handle in accordance with this Manual all PMN's and any reports prepared by MITRE that contain information claimed to be confidential.

Dated: September 25, 1979.

Marilyn C. Bracken,

Deputy Assistant Administrator for Program Integration and Information.

[FR Doc. 79-31015 Filed 10-4-79; 8:45 am]

BILLING CODE 6560-01-M

[FRL 1335-1; OPP 30033]

Privacy Act; Proposed New System of Records; Amendment

AGENCY: U.S. Environmental Protection Agency, Office of Pesticide Programs (OPP).

ACTION: Amended notice of proposed new system of records.

SUMMARY: Changes are being made to the implementation date, retention and disposal procedures, and comment procedures originally published.

SYSTEM NAME: Time Accounting Information System (EPA-12).

SUPPLEMENTARY INFORMATION: In the Federal Register Notice of September 7, 1979 (44 FR 52332). November 5, 1979 was indicated as the implementation date for the Time Accounting Information System (TAIS). In addition, interested parties were given until October 8, 1979 to comment on the proposed system. The OPP has received from the OMB a waiver of the 60-day advance notice period required by the OMB circular pertaining to the Privacy Act. As of October 3, 1979 the Office of Pesticide Programs has received no written comments concerning the TAIS. The Office of Pesticide Programs will implement the system effective October 9, 1979. Comments received after publication of this notice will be considered on their merit, and if modifications are required to the system (in the judgment of the system manager) because of these comments, they will be made. Time Accounting Information System Recording Sheets (EPA Hq Form 7710-30) submitted every two weeks by participating employees will be retained for two months after submission, then destroyed according to established procedures distributed in writing by the system manager.

Dated: October 2, 1979.

Walter W. Muelken,

Acting Deputy Assistant Administrator for Pesticide Program.

[FR Doc. 79-31104 Filed 10-4-79; 9:21 am]

BILLING CODE 6560-01-M

EQUAL EMPLOYMENT OPPORTUNITY COMMISSION

Request for Public Comment

AGENCY: Equal Employment Opportunity Commission.

ACTION: Solicitation of Public Comment Concerning Aggregating Minority Groups for Purpose of Goals and Timetables in Equal Employment Opportunity and Affirmative Action Programs.

SUMMARY: The Equal Employment Opportunity Commission ("EEOC") seeks public comment on an issue raised by a proposal by the Office of Federal Contract Compliance Programs (OFCCP) contained in "Proposed Goals and Timetables for Minority Participation in the Construction Industry", 44 F.R. 52348 (September 7, 1979). The issue concerns establishment of a single, combined minority goal in terms of a percentage figure for each Standard Metropolitan Statistical Area (SMSA) and each non-SMSA county in the United States. Public comment is sought on the practice of aggregating minority groups as opposed to setting a separate percentage goal for each minority group.

COMMENT DATE: Written comments should be submitted on or before December 4, 1979.

ADDRESS: Written comments should be addressed to: Francesta E. Farmer, Director, Office of Interagency Coordination, Equal Employment Opportunity Commission, Room 2534, 2401 "E" Street, N.W., Washington, D.C. 20506.

FOR FURTHER INFORMATION CONTACT: Francesta E. Farmer, Director, Office of Interagency Coordination, Equal Employment Opportunity Commission, Room 2534, 2401 "E" Street, N.W., Washington, D.C. 20506. Telephone: (202) 653-5490.

SUPPLEMENTARY INFORMATION: Under Executive Order 12067, the Equal Employment Opportunity Commission ("EEOC"), is given the responsibility to review all rules, regulations, policies, procedures or orders concerning equal employment opportunity to ensure consistency among the various Federal departments and agencies. An inconsistency exists on the question of aggregating minority groups between the programs and policies of the Office of Federal Contract Compliance Programs (OFCCP) and the EEOC. Most recently, the OFCCP published its "Proposed Goals and Timetables for Minority Participation in the Construction Industry" in the Federal Register on September 7, 1979 (Vol. 44, No. 175). This publication sets forth a single combined minority goal for each Standard Metropolitan Statistical Area (SMSA) and each non-SMSA county in the United States.

In reviewing OFCCP's proposed issuance on minority construction goals under Executive Order 12067, the EEOC, while granting interim approval for purposes of publication, requested public comment on the issue of the practice of aggregating minority groups as against setting separate goals for individual race and national origin groups based upon their particular representation in the area. Because the OFCCP notice of September 7, 1979 was published by inadvertency excluding this EEOC request, both agencies have agreed upon this notice as a means of remedying that exclusion.

The EEOC is inviting comment on this issue from the public for a period of 60 days from publication.

Signed at Washington, D.C., this 27th day of September, 1979.

For the Commission.

Eleanor Holmes Norton,

Chair.

[Fr Doc. 79-30444 Filed 10-4-79; 8:45 am]

BILLING CODE 6570-06-M

FEDERAL MARITIME COMMISSION

[Independent Ocean Freight Forwarder License No. 539]

Joseph A. Johnson; Order of Revocation

On September 21, 1979, Joseph A. Johnson, 315 Avenue "C", Apt. 10-D, New York, New York 10009, voluntarily surrendered his Independent Ocean Freight Forwarder License No. 539 for revocation.

Therefore, by virtue of authority vested in me by the Federal Maritime Commission as set forth in Manual of Orders, Commission Order No. 201.1 (Revised), section 5.01(c), dated August 8, 1977;

It is ordered, that Independent Ocean Freight Forwarder License No. 539 issued to Joseph A. Johnson, be and is hereby revoked effected September 21, 1979, without prejudice to reapplication for a license in the future.

It is further ordered, that a copy of this Order be published in the Federal Register and served upon Joseph A. Johnson.

Robert G. Drew,

Director, Bureau of Certification and Licensing.

[FR Doc. 79-31030 Filed 10-4-79; 8:45 am]

BILLING CODE 6730-01-M

[Independent Ocean Freight Forwarder License No. 23]

Hensel, Bruckmann & Lorbacher, Inc., and Hamilton Forwarding; Order of Revocation

September 26, 1979.

On August 20, 1979, Hensel, Bruckmann & Lorbacher, Inc. and Hamilton Forwarding, One Whitehall Street, New York, New York 10004, requested the Commission to revoke its Independent Ocean Freight Forwarder License No. 23, effective September 21, 1979.

Therefore, by virtue of authority vested in me by the Federal Maritime Commission as set forth in Manual of Orders, Commission Order No. 201.1 (Revised), section 5.01(c), dated August 8, 1977;

It is ordered, that Independent Ocean Freight Forwarder License No. 23 issued to Hensel, Bruckmann & Lorbacher, Inc. and Hamilton Forwarding, be and is hereby revoked effective September 21, 1979, without prejudice to reapplication for a license in the future.

It is further ordered, that Independent Ocean Freight Forwarder License No. 23 issued to Hensel, Bruckmann & Lorbacher, Inc. and Hamilton Forwarding be returned to the Commission for cancellation.

It is further ordered, that a copy of this Order be published in the Federal Register and served upon Hensel, Bruckmann & Lorbacher, Inc. and Hamilton Forwarding.

Robert G. Drew,

Director, Bureau of Certification and Licensing.

[FR Doc. 79-31003 Filed 10-4-79; 8:45 am]

BILLING CODE 6730-01-M

FEDERAL RESERVE SYSTEM

Chadron Banshares, Inc.; Formation of Bank Holding Company

Chadron Banshares, Inc., Chadron, Nebraska, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. 1842(a)(1)) to become a bank holding company by acquiring 99.80 per cent of the voting shares of Bank of Chadron, Chadron, Nebraska. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Kansas City. Any person wishing to comment on the application should submit views in writing to the Secretary, Board of Governors of the Federal Reserve

System, Washington, D.C. 20551 to be received no later than October 29, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, September 27, 1979.

Griffith L. Garwood,

Deputy Secretary of the Board.

[FR Doc. 79-30903 Filed 10-4-79; 8:45 am]

BILLING CODE 6210-01-M

First Mangum Corp.; Formation of Bank Holding Company

First Mangum Corp., Mangum, Oklahoma, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. 1842(a)(1)) to become a bank holding company by acquiring 80 per cent or more of the voting shares of First National Bank of Mangum, Mangum, Oklahoma. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Kansas City. Any person wishing to comment on the application should submit views in writing to the Reserve Bank, to be received not later than October 29, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, September 28, 1979.

Griffith L. Garwood,

Deputy Secretary of the Board.

[FR Doc. 79-30904 Filed 10-4-79; 8:45 am]

BILLING CODE 6210-01-M

Gordon State Banshares, Inc.; Formation of Bank Holding Company

Gordon State Banshares, Inc., Gordon, Nebraska, has applied for the Board's approval under section 3(a)(1)) of the Bank Holding Company Act (12 U.S.C. 1842(a)(1) to become a bank holding company by acquiring 100 per cent of the voting shares of Gordon State Bank, Gordon, Nebraska. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Kansas City. Any person wishing to comment on the application should submit views in writing to the Secretary, Board of Governors of the Federal Reserve System, Washington, D.C. 20551 to be received no later than October 29, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, September 27, 1979.

Griffith L. Garwood,

Deputy Secretary of the Board.

[FR Doc. 79-30905 Filed 10-4-79; 8:45 am]

BILLING CODE 6210-01-M

Guardian Banshares, Inc.; Formation of Bank Holding Company

Guardian Bancshares, Inc., Alliance, Nebraska, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. 1842(a)(1)) to become a bank holding company by acquiring 99 per cent of the voting shares of Guardian State Bank and Trust Co., Alliance, Nebraska. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Kansas City. Any person wishing to comment on the application should submit views in writing to the Secretary, Board of Governors of the Federal Reserve System, Washington, D.C. 20551 to be received no later than October 29, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, September 27, 1979.

Griffith L. Garwood,

Deputy Secretary of the Board.

[FR Doc. 79-30906 Filed 10-4-79; 8:45 am]

BILLING CODE 6210-01-M

Hemingford Banshares, Inc.; Formation of Bank Holding Company

Hemingford Banshares, Inc., Hemingford, Nebraska, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. 1842(a)(1)) to become a bank holding company by acquiring 100 per cent of the voting shares of Bank of Hemingford, Hemingford, Nebraska. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Kansas City. Any person wishing to comment on the application should submit views in writing to the Secretary, Board of Governors of the Federal Reserve System, Washington, D.C. 20551 to be received no later than October 29, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, September 27, 1979.

Griffith L. Garwood,

Deputy Secretary of the Board.

[FR Doc. 79-30907 Filed 10-4-79; 8:45 am]

BILLING CODE 6210-01-M

Hyannis Banshares, Inc., Formation of Bank Holding Company

Hyannis Banshares, Inc., Hyannis, Nebraska, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. 1842(a)(1)) to become a bank holding company by acquiring 87.33 percent of the voting shares of Bank of Hyannis, Hyannis, Nebraska. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Kansas City. Any person wishing to comment on the application should submit views in writing to the Secretary, Board of Governors of the Federal Reserve System, Washington, D.C. 20551 to be received no later than October 29, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, September 27, 1979.

Griffith L. Garwood,

Deputy Secretary of the Board.

[FR Doc. 79-30908 Filed 10-4-79; 8:45 am]

BILLING CODE 6210-01-M

Mullen Banshares, Inc., Formation of Bank Holding Company

Mullen Banshares, Inc., Mullen, Nebraska, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. 1842(a)(1)) to become a bank holding company by acquiring 100 per cent of the voting shares of Bank of Mullen, Mullen, Nebraska. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Kansas City. Any person wishing to comment on the application should submit views in writing to the Secretary, Board of Governors of the Federal Reserve System, Washington, D.C. 20551 to be received no later than October 29, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, September 27, 1979.

Griffith L. Garwood,

Deputy Secretary of the Board.

[FR Doc. 79-30909 Filed 10-4-79; 8:45 am]

BILLING CODE 6210-01-M

Pacwest Bancorp; Formation of Bank Holding Company

Pacwest Bancorp; Milwaukie, Oregon, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. 1842(a)(1)) to become a bank holding company by acquiring 100 per cent of the voting shares of First State Bank of Oregon, Milwaukie, Oregon; The Community Bank, Lake Oswego, Oregon; The First National Bank McMinnville, McMinnville, Oregon; and Hood River County Bank, Hood River, Oregon. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of San Francisco. Any person wishing to comment on the application should submit views in writing to the Reserve Bank, to be received not later than October 29, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, September 27, 1979.

Griffith L. Garwood,

Deputy Secretary of the Board.

[FR Doc. 79-30910 Filed 10-4-79; 8:45 am]

BILLING CODE 6210-01-M

Thedford Banshares, Inc.; Formation of Bank Holding Company

Thedford Banshares, Inc., Thedford, Nebraska, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. 1842(a)(1)) to become a bank holding company by acquiring 100 per cent of the voting shares of Citizens State Bank, Thedford, Nebraska. The factors that are considered in acting on the application are set forth in 3(c) of the Act (12 U.S.C. 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Kansas City. Any person wishing to comment on the application should submit views in writing to the Secretary, Board of Governors of the Federal Reserve System, Washington, D.C. 20551 to be received no later than October 29, 1979. Any comment on an applicaiton that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, September 27, 1979.

Griffith L. Garwood,

Deputy Secretary of the Board.

[FR Doc. 79-30911 Filed 10-4-79; 8:45 am]

BILLING CODE 6210-01-M

Valentine State Banshares, Inc.; Formation of Bank Holding Company

Valentine State Banshares, Inc., Valentine, Nebraska, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. 1842(a)(1)) to become a bank holding company by acquiring 98.51 per cent of the voting shares of Bank of Valentine, Valentine, Nebraska. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Kansas City. Any person wishing to comment on the application should submit views in writing to the Secretary, Board of Governors of the Federal Reserve System, Washington, D.C. 20551 to be received no later than October 29, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, September 27, 1979.

Griffith L. Garwood,

Deputy Secretary of the Board.

[FR Doc. 79-30913 Filed 10-4-79; 8:45 am]

BILLING CODE 6210-01-M

Yellowstone Holding Co., Formation of Bank Holding Company

Yellowstone Holding Company, Columbus, Montana, has applied for the Board's approval under section 3(a)(1) of the Bank Holding Company Act (12 U.S.C. 1842(a)(1)) to become a bank holding company by acquiring 100 per cent of the voting shares of The Yellowstone Bank, Absarokee, Montana; The Yellowstone Bank, Columbus, Montana; and The Yellowstone Bank, Laurel, Montana. The factors that are considered in acting on the application are set forth in section 3(c) of the Act (12 U.S.C. 1842(c)).

The application may be inspected at the offices of the Board of Governors or at the Federal Reserve Bank of Minneapolis. Any person wishing to comment on the application should submit views in writing to the Secretary, Board of Governors of the Federal Reserve System, Washington, D.C. 20551 to be received no later than October 29, 1979. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Board of Governors of the Federal Reserve System, September 27, 1979.

Griffith L. Garwood,

Deputy Secretary of the Board.

[FR Doc. 79-30912 Filed 10-4-79; 8:45 am]

BILLING CODE 6210-01-M

GENERAL SERVICES ADMINISTRATION

[Intervention Notice—99; Recommending Filing a Complaint Against the Gas Company of New Mexico]

Gas Company of New Mexico, the New Mexico Public Service Commission; Proposed Complaint Concerning Gas Rates

The General Services Administration seeks to file a complaint with the New Mexico Public Service Commission alleging overcharges by the Gas Company of New Mexico. GSA represents the interests of the executive agencies of the U.S. Government as users of natural gas services for which the overcharges are alleged.

Persons desiring to make inquiries to GSA concerning to this proposed complaint should submit them in writing to Spence W. Perry, Assistant General Counsel, Regulatory Law Division, General Services Administration, 18th & F Streets, NW., Washington, DC (mailing address: General Services Administration (LT), Washington, DC 20405), telephone 202-566-0750, on or before November 5, 1979, and refer to this notice number.

Persons making inquiries are put on notice that the making of an inquiry shall not serve to make any persons parties of record in the proceeding.

(Sec. 201(a)(4), Federal Property and Administrative Services Act, (40 U.S.C. 481(a)(4).)

Dated: September 26, 1979.

R. G. Freeman III,

Administrator of General Services.

[FR Doc. 79-30844 Filed 10-4-79; 8:45 am]

BILLING CODE 6820-AM-M

[Intervention Notice 100; Formal Case No. 725]

Potomac Electric Power Co., the Public Service Commission of the District of Columbia; Proposed Intervention in Investigation of Electric Fuel Adjustment Clause

The General Services Administration seeks to intervene in an investigation before the Public Service Commission of the District of Columbia concerning the Potomac Electric Power Company's fuel adjustment clause. GSA represents the interests of the executive agencies of the U.S. Government as users of electric utility service.

Persons desiring to make inquiries to GSA concerning this investigation should submit them in writing to Spence W. Perry, Assistant General Counsel, Regulatory Law Division, General Services Administration, 18th & F Streets, N.W., Washington, DC (mailing address: General Services Administration (LT), Washington, DC 20405), telephone 202-566-0750, within 30 days of the publication of this notice in the Federal Register, and refer to this notice number.

Persons making inquiries are put on notice that the making of an inquiry shall not serve to make any persons parties of record in the proceeding.

[Section 201(a)(4), Federal Property and Administrative Services Act, 40 U.S.C. 481(a)(4)]

Dated: September 27, 1979

R. G. Freeman III,

Administrator of General Services.

[FR Doc. 79-31007 Filed 10-4-79; 8:45 am]

BILLING CODE 6820-AM-M

Regional Public Advisory Panel on Architectural and Engineering Services; Meeting

September 21, 1979.

Pursuant to Public Law 92-463, notice is hereby given of a meeting of the Regional Public Advisory Panel on Architectural and Engineering Services, Region 1, on October 24, 1979, from 9:00 a.m. to 4:00 p.m., Room 711, J.W. McCormack Post Office and Courthouse, Post Office Square, Boston, MA 02109.

The meeting will be devoted to reviewing design concept drawings for the following project: Courthouse & Federal Building, Springfield, MA, GS-01B-91781.

This meeting will be open to the public.

L. F. Bretta,

Regional Administrator.

[FR Doc. 79-31008 Filed 10-4-79; 8:45 am]

BILLING CODE 6820-23-M

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE

Center for Disease Control

Project Grants Relative to Fluoridation and Influenza Immunization; Delegation of Authority

Notice is hereby given that pursuant to the May 24, 1976 delegation by the Secretary of Health, Education, and Welfare to the Assistant Secretary for Health (41 FR 22117) of authority under Section 317 of the Public Health Service Act, as amended, the Assistant Secretary for Health delegated, effective September 18, 1979, to the Director, Center for Disease Control, with authority to redelegate, the authroity to:

(1) Administer preventive health service programs relative to fluoridation, including the authority to award fluoridation grants to States and, in consultation with State health authorities, to political subdivisions of States and to other public entities; and

(2) Administer an influenza immunization grant program for the fiscal year 1979, including the authority to award influenza immunization grants to States and, in consultation with State health authorities, to political subdivisions of States and to other public entities with funds available in only fiscal year 1979 and the authority to make revisions to those grants after September 30, 1979 to the extent that 1980 appropriations are not involved.

The May 24, 1976 delegation by the Assistant Secretary for Health to the Regional Health Administrators (41 FR 22117) has been superseded insofar as it pertains to the authority herein cited as having been delegated to the Director, Center for Disease Control.

Dated: September 18, 1979.

Julius B. Richmond,

Assistant Secretary for Health.

[FR Doc. 79-31009 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-86-M

Food and Drug Administration

Consumer Participation; Open Meeting

Correction

In FR Doc. 79-27865, appearing on page 52336 in the issue of Friday, September 7, 1979, make the following correction:

On page 52336, in the middle column, the paragraph beginning "**SUPPLEMENTARY INFORMATION:**", the second line from the bottom should have read "consumers and FDA's Newark District Office, and to contribute to the agency's policymaking".

BILLING CODE 1505-01-M

[Docket No. 77N-0203; DESI 11961]

Isocar boxazid; Drugs for Human Use; Drug Efficacy Study Implementation; Permission for Drugs To Remain on the Market; Amendment

Correction

In FR Doc. 79-26652 appearing in page 50409 in the issue Tuesday, August 28, 1979, "Docket No. 77N-0203; DESI 11961" should have appeared in the heading as set forth above.

BILLING CODE 1505-01-M

[Docket No. 79N-0269]

Safety of Iron and Iron Salts; Opportunity for Public Hearing

Correction

In FR Doc. 79-26648 appearing on page 50414 in the issue of Tuesday, August 28, 1979, make the following corrections:

(1) In the table at the bottom of page 50414, first line, "BP-221-236 . . ." should have read "PB-221-236 . . .".

(2) At the end of the table, add the footnote,

*Prices subject to change.

(3) In the first column of page 50416, third paragraph, sixth line, ". . . Rm. 4-56 . . ." should have read ". . . Rm. 4-65 . . .".

BILLING CODE 1505-01-M

[Docket No. 79N-0322]

Safety of Certain Food Ingredients; Opportunity for Public Hearing

Correction

In FR Doc. 79-26649 appearing on page 50412 in the issue of Tuesday, August 28, 1979, in the table on page 50413 add the footnote:

*Price subject to change.

Also, in the first column of the page, seven lines from the bottom, ". . . Rm. 4-56 . . ." should have read ". . . Room 4-65 . . .".

BILLING CODE 1505-01-M

[Docket No. 79N-0138; DESI 11836]

Amitripyline Hydrochloride; Drugs for Human Use; Drug Efficacy Study Implementation; Followup Notice and Opportunity for Hearing, Amendment

AGENCY: Food and Drug Administration (FDA).

ACTION: Notice.

SUMMARY: This notice amends a notice which stated the conditions for marketing amitriptyline hydrochloride products for the indication for which they continue to be regarded as effective and offers an opportunity for a hearing concerning those indications reclassified as lacking substantial evidence of effectiveness. The drug is used for relief of symptoms of depression.

DATES: Hearing requests due on or before November 5, 1979; bioavailability supplements due on or before April 2, 1980; other supplements and data in support of hearing requests due on or before December 4, 1979.

ADDRESSES: Communications forwarded in response to this notice should be identified with the reference number DESI 11836, directed to the attention of the appropriate office named below, and addressed to the Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857.

Request for Hearing (identify with Docket number appearing in the heading of this notice): Hearing Clerk, Food and Drug Administration (HFA-305), Rm. 4-65.

Requests for the report of the National Academy of Sciences-National Research Council: Public Records and Documents Center (HFI-35), Rm. 12A-12.

Requests for guidelines and prospective test specifications for conducting bioavailability tests: Division of Biopharmaceutics (HFD-520), Bureau of Drugs.

Other communications regarding this notice: Drug Efficacy Study Implementation Project Manager (HFD-501), Bureau of Drugs.

FOR FURTHER INFORMATION CONTACT: Suzanne O'Shea, Bureau of Drugs (HFD-32), Food and Drug Administration, Department of Health, Education, and Welfare, 5600 Fishers Lane, Rockville, MD 20857, 301-443-3650.

SUPPLEMENTARY INFORMATION: In the Federal Register of May 25, 1979 (44 FR 30432), the Director of the Bureau of Drugs reclassified the possibly effective indications for amitriptyline hydrochloride to lacking substantial evidence of effectiveness, proposed to issue an order withdrawing approval of new drug applications providing for that indication, and offered an opportunity for a hearing on the proposed order. The Director also stated the conditions under which amitriptyline hydrochloride may continue to be marketed for the indication for which it is regarded as effective.

The May 25, 1979 notice specifically referred to new drug applications for Elavil Tablets (NDA 12-703) and Elavil Injection (NDA 12-704) manufactured by Merck Sharp & Dohme, but inadvertently omitted the abbreviated new drug applications for amitriptyline hydrochloride. Therefore, the notice of May 25, 1979 is now being amended to include the following abbreviated new drug applications:

ANDA's 85-627; 85-742; 85-743; 85-744; 85-745; amitriptyline hydrochloride tablets of 25, 100, 75, 10, and 50 milligrams; all manufactured by Barr Laboratories, 265 Livingston St., Northvale, NJ 07647.

ANDA's 84-910; 85-030; 85-031; 85-032; 85-836; amitriptyline hydrochloride tablets of 10, 75, 25, 50, and 100 milligrams; all manufactured by Biocraft Laboratories, Inc., 92 Rte. 46, Elmwood Park, NJ 07407.

ANDA's 85-815; 85-816; 85-817; 85-819; 85-820; 85-821; amitriptyline hydrochloride tablets of 50, 10, 25, 75, 100, and 150 milligrams; all manufactured by Chelsea Laboratories, 428 Doughty Blvd., Inwood, NY 11696.

ANDA's 85-594; amitriptyline hydrochloride intramuscular injection 10 milligram/milliliter; manufactured by Carter-Glogau Laboratories, 5160 West Bethany Home Rd., Glendale, AZ 85301.

ANDA's 85-966; 85-967; 85-968; 85-969; 85-970; 85-971; amitriptyline hydrochloride tablets of 25, 100, 50, 10, 150, and 75 milligrams; all manufactured by Cord Laboratories, Inc., 2555 West Midway Blvd., Broomfield, CO 80020.

ANDA's 85-922; 85-923; amitriptyline hydrochloride tablets of 25 and 10 milligrams; manufactured by Halsey Drug Co., Inc., 1827 Pacific St., Brooklyn, NY 11233.

ANDA's 83-639; 85-303; Endep Tablets; of 10, 25, 50, 75, 100, and 150 milligrams; and

ANDA's 85-749; Endep Oral Concentrate; 40 milligram/milliliter; all containing amitriptyline hydrochloride; all manufactured by Roche Laboratories, Division of Hoffmann-LaRoche, Inc., 340 Kingsland Rd., Nutley, NJ 07110.

ANDA's 86-743; 86-744; 86-745; 86-746; 86-747; amitriptyline hydrochloride tablets of 50, 10, 75, 25, and 100 milligrams; all manufactured by Lederle Laboratories, Division of American Cyanimid Co., North Middletown Rd., P.O. Box 500, Pearl River, NY 10965.

ANDA's 85-864; 85-935; 85-936; 86-335; 86-336; 86-337; amitriptyline hydrochloride tablets of 10, 25, 50, 150, 100, 75 milligrams; all manufactured by MD Pharmaceuticals, Inc., 3501 West Garry Ave., Santa Ana, CA 92704.

ANDA's 86-009; 86-010; 86-011; 86-153; 86-157; 86-158; amitriptyline hydrochloride tablets of 50, 25, 75, 150, 10, and 100 milligrams; all manufactured by Mylan Pharmaceuticals, Inc., P.O. Box 4293; Morgantown, WV 26505.

ANDA's 85-944; 85-945; 86-002; 86-003; 86-004; 86-090; amitriptyline hydrochloride tablets of 25, 50, 10, 100, 75, and 150 milligrams; manufactured by Philips Roxane Laboratories, Inc., 330 Oak St., P.O. 1738, Columbus, OH 43216.

ANDA's 86-143; 86-144; 86-145; 86-146; 86-147; 86-148; amitriptyline hydrochloride tablets of 50, 10, 25, 100, 75, and 150 milligrams; all manufactured by Philips Roxane Laboratories, Inc., for Smith, Kline & French Laboratories, 1500 Spring Garden St., P.O. Box 7929, Philadelphia, PA 19101.

ANDA's 86-498; 86-499; 86-500; 86-501; 86-502; 86-503; amitriptyline hydrochloride tablets of all 10, 50, 150, 100, 25, and 75 milligrams; manufactured by Smith, Kline & French Laboratories.

ANDA 86-454; Amitriptyline hydrochloride tablets of 10, 25, 50, 75, and 100 milligrams; manufactured by E. R. Squibb & Sons, Georges Road, P.O. Box 191, New Brunswick, NJ 08903.

ANDA's 83-937; 83-938; 83-939; 84-957; 85-093; 86-295; Amitril Tablets containing amitriptyline hydrochloride of 25, 50, 10, 75, 100, and 150 milligrams; all manufactured by Warner-Chilcott Laboratories, Division of Warner-Lambert Co., 201 Tabor Rd., P.O. Box W, Morris Plains, NJ 07950.

The **Federal Register** notice of May 25, 1979 described the data submitted in support of the indication reclassified to lacking substantial evidence of effectiveness, set forth the conditions for continued marketing of the drug products, and announced that bioavailability data is required for the tablet form of the product. For the ANDA's listed above, the supplements necessary for continued marketing must be submitted on or before December 4, 1979; bioavailability data must be submitted on or before April 2, 1980.

Merck Sharp and Dohme did not file a hearing request for Elavil Tablets and Injection and, therefore, has waived its opportunity for a hearing.

The abbreviated new drug applicants listed above who decide to seek a hearing, shall file (1) on or before November 5, 1979, a written notice of appearance and request for hearing, and (2) on or before December 4, 1979, the data, information, and analyses relied on to justify a hearing, as specified in 21 CFR 314.200. The procedures and requirements governing this notice of opportunity for hearing, a notice of appearance and request for hearing, a submission of data, information, and analyses to justify a hearing, other comments, and a grant or denial of hearing, are contained in 21 CFR 314.200.

The failure of an applicant to file timely written appearance and request for hearing as required by 21 CFR 314.200 constitutes an election by the person not to make use of the opportunity for a hearing on the action proposed for the product and constitutes a waiver of any contentions about the legal status of any such drug product. Any such drug product labeled for the indication(s) lacking substantial evidence of effectiveness referred to in paragraph A of the May 25, 1979 notice may not thereafter lawfully be marketed, and the Food and Drug Administration will initiate appropriate regulatory action to remove such drug products from the market. Any new drug product marketed without an approved NDA is subject to regulatory action at any time.

A request for a hearing may not rest upon mere allegations or denials, but must set forth specific facts showing that there is a genuine and substantial issue of fact that requires a hearing. If it conclusively appears from the face of the data, information, and factual analyses in the request for the hearing that there is no genuine and substantial issue of fact which precludes the withdrawal of approval of the application, or when a request for hearing is not made in the required format or with the required analyses, the Commissioner of Food and Drugs will enter summary judgment against the person(s) who requests the hearing, making findings and conclusions, denying a hearing.

All submissions pursuant to this notice are to be filed in quintuplicate. These submissions, except for data and information prohibited from public disclosure under 21 U.S.C. 331(j) or 18 U.S.C. 1905, may be seen in the office of the Hearing Clerk between 9 a.m. and 4 p.m., Monday through Friday.

This notice is issued under the Federal Food, Drug, and Cosmetic Act (sec. 505, 52 Stat. 1052-1053, as amended (21 U.S.C. 355)), and under the authority delegated to the Director of the Bureau of Drugs (21 CFR 5.82).

Dated: September 29, 1979.

J. Richard Crout,

Director, Bureau of Drugs.

[FR Doc. 79-30853 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-03-M

[Docket No. 77N-0390; DESI 5319]

Certain Radiopaque Drugs; Drugs for Human Use; Drug Efficacy Study Implementation; Correction

AGENCY: Food and Drug Administration.

ACTION: Notice.

SUMMARY: This notice corrects two previous notices to accurately state the formulations for E. R. Squibb & Sons' Renografin-60 and Renografin-76 injections (NDA 10-040).

FOR FURTHER INFORMATION CONTACT: Herbert Gerstenzang, Bureau of Drugs (HFD-32), Food and Drug Administration, Department of Health, Education, and Welfare, 5600 Fishers Lane, Rockville, MD 20857, 301-443-3650.

SUPPLEMENTARY INFORMATION: In a notice published in the **Federal Register** of June 18, 1971 (36 FR 11765), and a followup notice published February 17, 1978 (43 FR 7038), the Food and Drug Administration stated that E. R. Squibb & Sons' Renografin-60 and Renografin-76 injections contained only diatrizoate meglumine (NDA 10-040). This was an incorrect statement. Except for a brief period of a few months in 1969 and 1970 when these products contained only diatrizoate meglumine, the composition of these products has been as follows:

1. Renografin-60 containing diatrizoate meglumine 52 percent and diatrizoate sodium 8 percent;
2. Renografin-76 containing diatrizoate meglumine 66 percent and diatrizoate sodium 10 percent.

The products that contain diatrizoate meglumine and diatrizoate sodium were evaluated in the Drug Efficacy Study review. The products that contain only diatrizoate meglumine were not evaluated in the Study and therefore the conclusions of this notice do not apply to products containing diatrizoate meglumine 60 percent or diatrizoate meglumine 76 percent. No abbreviated new drug applications have been submitted pursuant to the previous **Federal Register** notices.

Accordingly, the notices described above are corrected as follows insofar as they pertain to Renografin-60 and Renografin-76:

1. The description of the drug products should read as follows:

NDA 10-040; Renografin-60 containing diatrizoate meglumine 52 percent and diatrizoate sodium 8 percent; and

Renografin-76 containing diatrizoate meglumine 66 percent and diatrizoate sodium 10 percent.

2. The text pertaining to these drug products in the Indications section should read as follows:

Diatrizoate Meglumine 52 Percent and Diatrizoate Sodium 8 Percent

For use in excretion urography; cerebral angiography; peripheral arteriography; venography; operative T-tube or percutaneous transhepatic cholangiography; splenoportography; arthrography; and discography.

Diatrizoate Meglumine 66 Percent and Diatrizoate Sodium 10 Percent

For use in excretory urography; aortography; pediatric angiocardiography; and peripheral arteriography.

This notice is issued under the Federal Food, Drug, and Cosmetic Act (secs. 502, 505, 52 Stat. 1050-1053, as amended 21 U.S.C. 352, 355), and under the authority delegated to the Director of the Bureau of Drugs (21 CFR 5.70).

Dated: September 27, 1979.
J. Richard Crout,
Director, Bureau of Drugs.
[FR Doc. 79-30852 Filed 10-4-79; 8:45 am]
BILLING CODE 4110-03-M

[Docket No. 79N-0324; DESI 6514]

Warner-Lambert/Parke-Davis & Co.; Benylin Cough Syrup; Drug Efficacy Study Implementation; Revocation of Exemption

AGENCY: Food and Drug Administration.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is revoking the temporary exemption under which Benylin Cough Syrup, a prescription drug, has been allowed to remain on the market labeled for its less-than-effective indication beyond the time limit scheduled for implementation of the Drug Efficacy Study. The temporary exemption is revoked because the effectiveness classification of this drug product has been resolved.

EFFECTIVE DATE: October 5, 1979.

FOR FURTHER INFORMATION CONTACT: Nathan J. Treinish, Bureau of Drugs (HFD-32), Food and Drug Administration, Department of Health, Education, and Welfare, 5600 Fishers Lane, Rockville, MD 20857, 301-443-3650.

SUPPLEMENTARY INFORMATION: The following prescription product has been allowed to remain on the market beyond the time limit established for implementing the Drug Efficacy Study pending FDA's review of all scientific data for over-the counter (OTC) cold, cough, or allergy products. The temporary exemption to permit continued marketing was announced in a notice published in the **Federal Register** of December 14, 1973 (38 FR 34481).

NDA 6-514; Benylin Cough Syrup containing diphenhydramine hydrochloride, ammonium chloride, sodium citrate, and menthol (formerly labeled as Benylin Expectorant); Parke-Davis, Division of Warner-Lambert Co., Morris Plains, NJ 07950.

After the December 14, 1973 notice was published, the firm submitted a supplemental new drug application (NDA) for the OTC marketing of Benylin Cough Syrup. FDA refused to approve the application and, at the firm's request, an evidentiary hearing was held. At the conclusion of the hearing, the Administrative Law Judge found that the drug product is effective for its recommended use and is safe for OTC use.

In a notice (Docket No. 76N-0483) published in the **Federal Register** of July 6, 1979 (44 FR 39619), FDA announced the availability of the Commissioner's final decision on the supplemental NDA for OTC distribution of Benylin Cough Syrup. The Decision was published in the **Federal Register** of August 31, 1979 (44 FR 51512). The Commissioner found that the drug product has not been shown to be effective for its claimed indication as an antitussive. The decision on effectiveness is equally applicable whether the drug product is marketed OTC or by prescription, and reverses the initial decision of the Administrative Law Judge.

The Commissioner's decision therefore resolves the effectiveness classification of Benylin Cough Syrup. Accordingly, the temporary exemption granted by the December 14, 1973 notice for this drug product is now revoked. Other drug products which are still exempt for continued marketing, as granted by the December 14, 1973 notice, are not affected by this notice.

It should also be noted that, in light of the finding that Benylin has not been shown to be effective as an antitussive drug, the Director of the Bureau of Drugs is now proposing elsewhere in this issue of the **Federal Register** to withdraw approval of the NDA for Benylin Cough Syrup for prescription use on the basis that the drug product lacks substantial evidence of effectiveness for its labeled indication as an antitussive.

This notice is issued under the Federal Food, Drug, and Cosmetic Act (secs. 502, 505, 52 Stat. 1050-1053, as amended (21 U.S.C. 352, 355)) and under authority delegated to the Commission of Food and Drugs (21 CFR 5.1).

Dated: September 28, 1979.
Joseph P. Hile,
Associate Commissioner for Regulatory Affairs.
[FR Doc. 79-30850 Filed 10-4-79; 8:45 am]
BILLING CODE 4110-03-M

[Docket No. 79N-0324; DESI 6514]

Warner-Lambert/Parke-Davis; Benylin Cough Syrup; Opportunity for Hearing on Proposal To Withdraw Approval of New Drug Application

AGENCY: Food and Drug Administration.

ACTION: Notice.

SUMMARY: This notice proposes to withdraw approval of the new drug application for a prescription drug, Benylin Cough Syrup (NDA 6-514), on the ground that it lacks substantial evidence of effectiveness as an antitussive for the control of cough due to colds or allergy. The agency offers an opportunity for hearing on the proposal.

DATES: Hearing requests due on or before November 5, 1979. Any *new* data and information relied upon in support of any such request and any other comments must be submitted on or before December 4, 1979.

ADDRESSES: Communications in response to this notice should be identified with the Docket No. 79N-0324 and the reference number DESI 6514 and directed to the attention of the appropriate office named below.

Requests for hearing, supporting data, and other comments: Hearing Clerk (HFA-305), Rm. 4-65, Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857.

Request for opinion of the applicability of this notice to a specific product: Division of Drug Labeling Compliance (HFD-310), Bureau of Drugs, Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857.

FOR FURTHER INFORMATION CONTACT: Nathan J. Treinish, Bureau of Drugs (HFD-32), Food and Drug Administration, Department of Health, Education, and Welfare, 5600 Fishers Lane, Rockville, MD 20857, 301-443-3650.

SUPPLEMENTARY INFORMATION:

DESI Review

In a notice published in the **Federal Register** of February 9, 1973 (38 FR 4006), the Food and Drug Administration (FDA) announced its conclusion after evaluating reports from the National Academy of Sciences-National Research Council, Drug Efficacy Study Group, on the following drug:

NDA 6-514; Benylin Cough Syrup (formerly labeled as Benylin Expectorant) containing diphenhydramine hydrochloride, ammonium chloride, sodium citrate, and menthol; Parke-Davis, Division of Warner Lambert Co., Morris Plains, NJ 07950.

The notice stated that Benylin Cough Syrup ("Benylin") and certain other products lack substantial evidence of effectiveness as fixed combinations for the indications in their labeling. The notice also gave the holders of the new drug applications and any other interested person an opportunity to request a hearing on a proposal to withdraw approval of the new drug applications. In response to the notice, Parke-Davis requested a hearing on the proposed withdrawal of Benylin.

In a **Federal Register** notice of December 14, 1973 (38 FR 34481), FDA granted a temporary exemption from the time limits established for completing certain phases of the drug efficacy study (DESI) program for certain oral prescription drugs offered for the relief of cough, cold, allergy, and related symptoms. That exemption included Benylin and the other drug products that were the subject of the February 9, 1973 notice mentioned above. The exemption was granted because of the close relationship between, and the similarities in, drugs sold over-the-counter (OTC) and thus subject to review in the ongoing OTC study (21 CFR Part 330), and prescription drugs such as Benylin offered for relief of cough, cold, allergies, and related symptoms, and the active ingredients common to them. Postponement of final evaluations on the DESI prescription products enabled the agency to consider the recommendations of the OTC Advisory Review Panel on OTC Cold, Cough, Allergy, Bronchodilator, and Antiasthmatic Drugs ("CCABA Panel") in addition to any evidence submitted by NDA holders in response to various DESI notices covering these drugs. The December 14, 1973 notice supercedes the February 9, 1973 notice of opportunity for hearing and the hearing requests submitted in response to the notice. The temporary exemption granted by the December 14, 1973 notice, as it pertains to Benylin (NDA 6-514) is, however, revoked in a notice appearing elsewhere in this issue of the **Federal Register.**

Supplemental NDA for OTC Marketing

By letter of November 25, 1974, Parke-Davis submitted a supplemental NDA with revised labeling providing for OTC use of Benylin as an antitussive. The firm had previously submitted another supplemental NDA on February 5, 1974, with two clinical studies relating to the effectiveness of Benylin as an antitussive.

FDA acknowledged receipt of both supplemental NDA's by letter of March 11, 1975, and stated that no action would be taken pending completion of the review by the CCABA Panel of the data before it. In a letter of March 18, 1975, Parke-Davis was informed, in response to its inquiry made to the Division of OTC Drug Evaluation, that OTC marketing of Benylin would be unlikely to be subject to regulatory action under the enforcement policy in effect at that time concerning new OTC products. Thereafter, Parke-Davis commenced OTC marketing of Benylin as Benylin Cough Syrup with indications for use as an antitussive.

In the August 4, 1976 **Federal Register** (41 FR 32580), FDA published a final regulation, based on a proposal published on December 4, 1975 (40 FR 56675), that changed the agency's enforcement policy concerning OTC marketing of drug ingredients that had previously been limited to prescription use and for which OTC use had not been approved by FDA. This regulation, codified in 21 CFR 310.200 and 330.13, allows that products containing such ingredients may be marketed OTC upon publication of the report of an OTC advisory panel recommending that the ingredients and indications be classified as generally recognized as safe and effective for OTC use (Category I) unless the Commissioner disagrees with that decision.

The Commissioner's proposal setting forth the report and recommendations of the CCABA Panel was published in the **Federal Register** of September 9, 1976 (41 FR 38312). The CCABA Panel recommended that diphenhydramine hydrochloride be classified in Category I for OTC use both as an antihistamine and as an antitussive. The Commissioner disagreed with the recommendation relating to antihistaminic use of diphenhydramine hydrochloride (and with the panel's recommendations that several other ingredients be similarly classified), but he stated that his decision on the recommendation relating to its antitussive use would be made in the context of his ruling on the supplemental NDA filed by Parke-Davis for OTC marketing of Benylin.

By letters dated September 8, 1976, the Bureau of Drugs notified Parke-Davis that its supplemental NDA's submitting evidence on the effectiveness of Benylin as an antitussive and labeling for OTC use of the product were not approvable. Final action on the supplemental NDA relating to the effectiveness of Benylin as an antitussive was deferred pending review of the data generated by the work of the CCABA Panel, as provided in the December 14, 1973 notice. Parke-Davis was informed, however, that the studies submitted to demonstrate the effectiveness of Benylin as an antitussive were inadequate in a number of respects. The supplemental NDA relating to the safety of Benylin for OTC use was denied because of the sedating properties of diphenhydramine hydrochloride and the absence in the proposed labeling of drug interaction and other warnings and contraindications.

By letter of September 17, 1976, Parke-Davis requested that the supplemental NDA for OTC use of Benylin be filed over protest under 21 CFR 314.110(d). In a notice published in the **Federal Register** of November 30, 1976 (41 FR 52537), the Bureau proposed to deny approval of the supplemental NDA for OTC marketing of Benylin and offered the firm an opportunity for a hearing on this proposed action. On the same date, the Commissioner published a notice (42 FR 52536) announcing that he did not, at that time, accept the CCABA Panel's recommendation that diphenhydramine hydrochloride be classified in Category I for OTC antitussive use. Accordingly, any OTC product marketed containing diphenhydramine hydrochloride was subject to immediate regulatory action. The Commissioner had concluded that the recommended antitussive dose of diphenhydramine hydrochloride (25 milligrams) causes an unacceptable level of drowsiness for an OTC drug. Furthermore, although he agreed with the Panel that some data indicated that this ingredient has some antitussive effect, he found that there was a lack of substantial evidence consisting of adequate and well-controlled studies, as required by 21 CFR 314.111(a)(5)(ii), on which to base a determination concerning the effectiveness of Benylin for the temporary control of cough.

On November 29, 1976, the firm filed an action seeking a declaratory judgment that Benylin is not a new drug or, in the alternative, an order enjoining FDA enforcement actions involving Benylin pending final determination of the drug's status (Civil Action No. 6-72464, E. D. Mich.). On November 30 and December 1, 1976, three United States Attorneys for other districts filed complaints resulting in seizures of Benylin. The Michigan case ultimately resulted in a decision by the United States Court of Appeals for the Sixth Circuit holding that the district court lacked jurisdiction to review the agency's decision to initiate enforcement action and that the pending enforcement actions provided an opportunity for a full hearing on all issues. *Parke, Davis & Co.* v. *Califano,* 564 F.2d 1200 (6th Cir. 1977), *rev'g Parke, Davis & Co.* v. *Mathews,* Civil Action No. 6-72464 (E. D. Mich., Memorandum Opinion issued Jan. 7, 1977), *cert. den.* 98 S. Ct. 1522 (1978).

Parke-Davis then submitted a request for hearing, which the Commissioner granted in a notice published in the **Federal Register** of March 29, 1977 (42 FR 16675).

Evidentiary Hearing

The March 29, 1977 notice of hearing observed that the issue of the effectiveness of Benylin as an OTC product is indistinguishable from the issue of its effectiveness as a prescription product and therefore announced that the hearing would concern the effectiveness of Benylin for prescription use as well as for OTC use.

For this reason, the Administrative Law Judge (ALJ) in a pretrial order dated June 2, 1977, broadened the issues at the hearing to include consideration of "whether there is any other evidence relating to the effectiveness of Benylin as an antitussive." The ALJ recognized that although the effectiveness of Benylin as a prescription antitussive is required to be resolved in a separate withdrawal proceeding, "there would be no need to duplicate the hearing process with respect to other evidence relating to the effectiveness of Benylin as an antitussive for prescription use."

The oral portion of the evidentiary hearing was held from October 11 through 25, 1977. The parties were the Bureau, in support of the proposed denial, and Parke-Davis in opposition to the proposed denial. Warner-Lambert also participated in the proceeding.

On May 31, 1978, the ALJ issued an initial decision in which he found that Benylin has been shown, by adequate investigation, to be safe and effective for use as an antitussive and ordered that the supplemental NDA (6-514/S-007) be approved.

On June 29, 1979, the Commissioner of Food and Drugs issued his final decision reversing the ALJ's initial decision. The decision was published in the Federal Register of August 31, 1979 (44 FR 51512). The Commissioner determined that Benylin has not been shown to be effective for its indicated use in the treatment of cough due to colds or inhaled irritants and refused to approve the supplemental NDA. In view of the decision on the effectiveness issue, the Commissioner did not decide whether Benylin is safe for OTC Distribution. The decision did not affect the approved NDA for marketing Benylin as a prescription antitussive. The finding that Benylin has not been shown to be effective for its recommended use is equally applicable whether the drug is marketed OTC or is subject to a prescription requirement. As a result of his finding, the Commissioner directed the Bureau of Drugs to consider whatever action is appropriate with respect to the approved NDA for prescription Benylin.

Conclusions

The Commissioner's decision made the following specific conclusions:

1. Parke-Davis has not shown that diphenhydramine hydrochloride acts to inhibit activity in the brain's cough center.

2. In the absence of a showing that diphenhydramine hydrochloride suppresses activity in the brain's cough center, Benylin's effectiveness as an antitussive drug for use in coughs due to colds may be established only by two or more studies in the target population.

3. The two studies of Benylin in patients with coughs due to cold (Tebrock study and Burke study) are not adequate and well-controlled investigations, as defined in section 505(d) of the act (21 U.S.C. 355(d)) and 21 CFR 314.111(a)(5)(ii). Acccordingly, there is a lack of "substantial evidence" as that term is defined in section 505(d) of the act that Benylin will have the effect it purports or is represented to have under the conditions of use prescribed, recommended, or suggested in the proposed labeling thereof.

4. Because it has not been shown that Benylin is effective, the Commissioner did not find that Parke-Davis has satisfied the requirements for establishing its safety for OTC distribution.

5. Benylin is not generally recognized, among experts qualified by scientific training and experience to evaluate the safety and effectiveness of drugs, as safe and effective for use under the conditions of use prescribed, recommended, or suggested in the proposed labeling thereof. Accordingly, Benylin is a new drug within the meaning of section 201(p)(1) of the act (21 U.S.C. 321(p)(1)).

In light of the Commissioner's conclusions, the Director of the Bureau of Drugs is now proposing to withdraw approval of the NDA for prescription use of Benylin on the ground that the drug product lacks substantial evidence of effectiveness for its labeled indication as an antitussive. As Benylin meets the requirements of safety when restricted to prescription use, the proposed withdrawal is based solely on the ground that there is a lack of substantial evidence of effectiveness as defined in section 505(d) of the Act. Accordingly, this notice of opportunity for hearing is being issued and, as previously noted, the temporary exemption granted by the December 14, 1973 notice, as it pertains to Benylin (NDA 6-514), is revoked in a notice appearing elsewhere in this issue of the Federal Register.

On the basis of all of the data and information available to him, the Director of the Bureau of Drugs is unaware of any adequate and well-controlled clinical investigations conducted by experts qualified by scientific training and experience, meeting the requirements of section 505 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 355), 21 CFR 314.111(a)(5), and 21 CFR 300.50 which provide substantial evidence of effectiveness for this drug.

In a notice (Docket No. 76N-0483), published in the Federal Register of July 6, 1979 (44 FR 39619), the agency announced the availability of the Commissioner's June 29 decision discussed earlier in this notice. The Commissioner's decision was based on all data that the firm submitted to the agency. That decision is incorporated herein by reference and is the basis of this notice. The decision, the transcript of the hearing, the evidence submitted, and all other related documents may be seen in the Office of the Hearing Clerk (HFA-305), Food and Drug Administration, Rm. 4-65, 5600 Fishers Lane, Rockville, MD 20857, from 9 a.m. to 4 p.m., Monday through Friday.

Notice of Opportunity for Hearing

Therefore, notice is given to the holder of the new drug application and to all other interested persons that the Director of the Bureau of Drugs proposes to issue an order under section 505(e) of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 355(e)), withdrawing approval of the new drug application providing for the drug product listed above and all amendments and supplements thereto on the ground that new information before him with respect to the drug product, evaluated together with the evidence available to him when the application was approved, shows there is a lack of substantial evidence that the drug product will have the effect it purports or is represented to have under the conditions of use prescribed, recommended, or suggested in the labeling.

In addition to the holder of the new drug application specifically named above, this notice of opportunity for hearing applies to all persons who manufacture or distribute a drug product that is identical, related, or similar to a drug product named above, as defined in 21 CFR 310.6. It is the responsibility of ever drug manufacturer or distributor to review this notice of opportunity for hearing to determine whether it covers any drug product that the person manufactures or distributes. Such person may request an opinion of the applicability of this notice to a specific drug product by writing to the Division of Drug Labeling Compliance (address given above).

In addition to the ground for the proposed withdrawal of approval stated above, this notice of opportunity for hearing encompasses all issues relating to the legal status of the drug products subject to it (including identical, related, or similar drug products as defined in 21 CFR 310.6) e.g., any contention that any such product is not a new drug because it is generally recognized as safe and effective within the meaning of section 201(p) of the act or because it is exempt from part or all of the new drug provisions of the act under the exemption for products marketed before June 25, 1938, contained in section 201(p) of the act, or under section 107(c) of the Drug Amendments of 1962 or for any other reason.

In accordance with section 505 of the act (21 U.S.C. 355) and the regulations promulgated thereunder (21 CFR Parts 310, 314), the applicant and all other persons subject to this notice pursuant to 21 CFR 310.6 are hereby given an opportunity for a hearing to show why approval of the new drug application should not be withdrawn and an opportunity to raise, for administrative determination, all issues relating to the legal status of the drug product named above and of the all identical, related, or similar drug products.

The applicant or any other person subject to this notice under 21 CFR 310.6 who decides to seek a hearing, shall file (1) on or before November 5, 1979, a written notice of appearance and request for hearing, and (2) on or before December 4, 1979, any *new* data, information, and analyses relied on to justify a hearing, as specified in 21 CFR 314.200. The Bureau will not reconsider any material which was submitted as part of the administrative proceeding (Docket No. 76N-0483) which resulted in the Commissioner's June 29, 1979 final order. Any other interested person may also submit comments on this notice. The procedures and requirements governing this notice of opportunity for hearing, a notice of appearance and request for hearing, a submission of data, information, and analyses to justify a hearing, other comments, and a grant or denial of hearing, are contained in 21 CFR 314.200.

The failure of an applicant or any other persons subject to this notice under 21 CFR 310.6 to file timely written appearance and request for hearing as required by 21 CFR 314.200 constitutes an election by the person not to make use of the opportunity for a hearing concerning the action proposed with respect to the product and constitutes a waiver of any contentions concerning the legal status of any such drug product. Any such drug product may not thereafter lawfully be marketed, and the Food and Drug Administration will initiate appropriate regulatory action to remove such drug products from the market. Any new drug product marketed without an approved NDA is subject to regulatory action at any time.

A request for a hearing may not rest upon mere allegations or denials, but must set forth specific facts showing that there is a genuine and substantial issue of fact that requires a hearing. If it conclusively appears from the face of the data, information, and factual analyses in the request for the hearing that there is no genuine and substantial issue of fact which precludes the withdrawal of approval of the application, or when a request for a hearing is not made in the required format or with the required analyses, the Commissioner of Food and Drugs will enter summary judgment against the person who requests the hearing, making findings and conclusions, denying a hearing.

All submissions pursuant to this notice shall be filed in quintuplicate. Such submissions except for data and information prohibited from public disclosure under 21 U.S.C. 331(j) or 18 U.S.C. 1905, may be seen in the office of the Hearing Clerk between 9 a.m. and 4 p.m., Monday through Friday.

This notice is issued under the Federal Food, Drug and Cosmetic Act (sec. 505, 52 Stat. 1052–1503 as amended (21 U.S.C. 355)), and under the authority delegated to the Director of the Bureau of Drugs (21 CFR 5.82).

Dated: September 7, 1979.

J. Richard Crout,

Director, Bureau of Drugs.

[FR Doc. 79-30851 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-03-M

[Docket No. 79N-0264]

Pesticide and Industrial Chemical Contaminants of Food; Availability of Report on FDA Residue Programs

AGENCY: Food and Drug Administration.

ACTION: Notice.

SUMMARY: The agency announces the availability of a report entitled "FDA Monitoring Programs for Pesticide and Industrial Chemical Residues in Food" that was prepared by the Study Group on FDA Residue Programs. The study group was charged with critically examining the agency's monitoring, analysis, and enforcement activities on chemical residues in food for man and other animals and, where necessary, presenting recommendations that would improve the effectiveness of these activities. The report has been accepted by the Commissioner of Food and Drugs.

ADDRESS: Copies of the report are available from the Office of Regulatory Affairs (HFC-6), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857.

FOR FURTHER INFORMATION CONTACT: John Wessel, Office of Regulatory Affairs (HFC-6), Food and Drug Administration, Department of Health, Education, and Welfare, 5600 Fishers Lane, Rockville, MD 20857, 301-443-1815.

SUPPLEMENTARY INFORMATION: In February 1978, the House Subcommittee on Oversight and Investigations held hearings on Federal programs to protect the public from toxic chemicals in food. The Environmental Protection Agency (EPA), the Food and Drug Administration (FDA), and the Food Safety and Quality Service (FSQS), United States Department of Agriculture testified. As a result of these hearings, the Subcommittee concluded that the EPA, FDA, and FSQS programs needed strengthening.

In his testimony before the Subcommittee, the Commissioner of FDA agreed that there was a need to improve the effectiveness of the agency's programs, and, in March 1978, the Commissioner established the Study Group on FDA Residue Programs to examine the agency's activities to safeguard the Nation's food supply from toxic chemicals. The study group limited its review to agency monitoring and enforcement activities involving pesticide and industrial chemical contaminants. The report represents a comprehensive and critical evaluation of these agency program activities and of the relationships of these FDA activities to those of Federal and State agencies that share responsibility for controlling chemical residues in the Nation's food supply.

The study group defined the objectives of FDA's statutory responsibilities relative to residues of pesticides and industrial chemicals in food to include the following:

1. Monitor domestic and imported food and feed commodities for chemical residues, and, when illegal residues are found, initiate regulatory action to ensure protection of the consumer.

2. Gather information on levels and incidence of chemical residues in the food supply (including the absence of residues) in order to enable FDA to:

a. Evaluate whether Federal regulations are effective.

b. Identify emerging chemical problems and deal with them before they become critical public health issues.

c. Establish supportable tolerances or action levels for industrial chemical residues in food and feed.

d. Provide EPA with information to support that agency's decisions on pesticide registrations, tolerances for pesticide residues, action levels recommended to FDA, toxic substances control, and pollution abatement.

e. Inform the public, Congress, industry, and other concerned groups about chemical residues in the American diet.

The study group identified nineteen issues that affect meeting these objectives. These issues involve almost every aspect of FDA's monitoring, analytical, and enforcement programs and their interactions with the Federal, State, and international agencies. The subjects discussed in the issue papers are as follows:

1. Residue selection criteria.
2. Intelligence gathering and early warning system.
3. Surveillance program design.
4. Joint Bureau of Foods and Bureau of Veterinary Medicine surveillance programs.
5. Total diet study program.
6. Analytical methods development.
7. Field analytical capabilities.
8. Administrative detention and civil penalties (fines).
9. Retrievable data on disposition of violative samples.
10. Critical chemical contamination incidents—emergency operations.
11. Evaluation of individual sample results.
12. Evaluation of completed residue program.
13. Residue data retrieval system.
14. FDA-EPA liaison on pesticide regulatory matters.
15. EPA national pesticide monitoring plan.
16. Chemical contamination of food—FSQS and FDA interaction.
17. USDA meat and poultry residue program—FSQS and FDA interaction.
18. State-FDA interaction.
19. International pesticide activities.

Persons interested in obtaining copies of the study group report should write to the Office of Regulatory Affairs (HFC-6), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857. A copy of this report is on display in the office of the Hearing Clerk, Food and Drug Administration, Rm. 4-65, 5600 Fishers Lane, Rockville, MD 20857, and may be seen in that office from 9 a.m. to 4 p.m., Monday through Friday.

Dated: September 25, 1979.

Sherwin Gardner,

Acting Commissioner of Food and Drugs.

[FR Doc. 79-30849 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-03-M

National Institutes of Health

Animal Resources Review Committee; Meeting

Pursuant to Pub. L. 92-463, notice is hereby given of the meeting of the Animal Resources Review Committee, Division of Research Resources, October 30, 1979, at the Tennis Club Hotel, 4120 Chiles Road, Davis, California 95616.

The meeting will be open to the public on October 30 from 1:00 p.m. to 2:30 p.m., during which time there will be a brief staff presentation on the current status of the ARB Program as it relates to the function of the Primate Research Centers and the current status of primate supply. The Committee will select future meeting dates. Attendance by the public will be limited to space available.

In accordance with the provisions set forth in Sections 552b(c)(4) and 552b(c)(6), Title 5, U.S. Code and Section 10(d) of Pub. L. 92-463, the meeting will be closed to the public on October 30 from 2:30 p.m. to adjournment for the review, discussion, and evaluation of individual grant applications. These applications and the discussions could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Mr. James Augustine, Information Officer, Division of Research Resources, Room 5B13, Building 31, National Institutes of Health, Bethesda, Maryland 20205, (301) 496-5545, will provide summaries of the meeting and rosters of the Committee members. Dr. Dennis O. Johnsen, Executive Secretary of the Animal Resources Review Committee, Room 5B55, Building 31, National Institutes of Health, Bethesda, Maryland 20205, (301) 496-5175, will furnish substantive program information.

(Catalog of Federal Domestic Assistance Programs No. 13.306, National Institutes of Health)

Dated: September 27, 1979.

Suzanne L Fremeau,

NIH Committee Management Officer.

[FR Doc. 79-30862 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-08-M

Clinical Applications and Prevention Advisory Committee; Meeting

Pursuant to Public Law 92-463, notice is hereby given of the meeting of the Clinical Applications and Prevention Advisory Committee, Division of Heart and Vascular Diseases, National Heart, Lung, and Blood Institute, November 2, 1979, Federal Building, Conference Room 6C01, Bethesda, Maryland.

This meeting will be open to the public on November 2 from 9:30 a.m. to 10:30 a.m. when the current progress of the Multiple Risk Factor Intervention Trial will be discussed. Attendance by the public will be limited to space available.

In accordance with provisions set forth in Sections 552b(c)(4) and 552b(c)(6), Title 5, U.S. Code and Section 10(d) of Public Law 92-463, the meeting will be closed to the public on November 2, from 10:30 a.m. to adjournment, for the review, discussion and evaluation of individual contract renewal proposals. The proposals and the discussions could reveal confidential trade secrets or commercial property such a patentable material, and personal information concerning individuals associated with the proposals, disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Mr. York Onnen, Chief, Public Inquiries and Reports Branch, National Heart, Lung, and Blood Institute, Building 31, Room 4A21 National Institutes of Health, Bethesda, Maryland 20205, phone (301) 496-4236, will provide summaries of meetings and rosters of committee members. Dr. William T Friedewald, Executive Secretary of the Committee, Federal Building, Room 212, Bethesda, Maryland 20205, phone (301) 496-2533, will furnish substantive program information.

(Catalog of Federal Domestic Assistance Program No. 13.837, National Institutes of Health)

Dated: October 1, 1979.

Suzanne L. Fremeau,

Committee Management Officer, NIH.

[FR Doc. 79-30866 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-08-M

General Clinical Research Centers Committee; Meeting

Pursuant to Public Law 92-463, notice is hereby given of the meeting of the General Clinical Research Centers Committee, Division of Research Resources, November 19-20, 1979. The meeting will be held in Conference Room 8, Bldg. 31-C, National Institutes of Health, Bethesda, Maryland 20205.

The meeting will be open to the public on November 19, 1979, from 9:00 a.m. to 11:00 a.m., to discuss administrative matters. Attendance by the public will be limited to space available.

In accordance with the provisions set forth in Sections 552b(c)(4) and 552b(c)(6), Title 5, U.S. Code and Section 10(d) of P.L. 92-463, the meeting will be closed to the public on November 19, 1979, from 11:00 a.m. to recess and on November 20, from 8:00 a.m. to adjournment for the review, discussion, and evaluation of individual grant applications. These applications and the discussions could reveal confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the applications, disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Mr. James Augustine, Information Officer, Division of Research Resources, Bldg. 31, Rm. 5B-13, National Institutes of Health, Bethesda, Maryland 20205, (301) 496-5545 will provide summaries of the meeting and rosters of the Committee members. Dr. Ephraim Y. Levin, Executive Secretary of the General Clinical Research Centers Review Committee, Bldg. 31, Rm. 5B51 National Institutes of Health, Bethesda, Maryland 20205, (301) 496-6595, will furnish substantive program information.

(Catalog of Federal Domestic Assistance Program No. 13.333, National Institutes of Health)

Dated: October 1, 1979.

Suzanne L. Fremeau,

Committee Management Officer National Institutes of Health.

[FR Doc. 79-30864 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-08-M

Clinical Trials Review Committee; Meeting

Pursuant to Public Law 92-463, notice is hereby given of the Clinical Trials Review Committee, National Heart, Lung, and Blood Institute, November 18-20, 1979, at the Sheraton Ritz Hotel, 315 Nicollet Mall, Minneapolis, Minnesota, at 8:00 p.m. on November 18, 1979.

This meeting will be open to the public from 8:00 p.m. to 9:00 p.m. on November 18, 1979, to discuss administrative details and to hear a report concerning the current status of the National Heart, Lung, and Blood Institute. Attendance by the public will be limited to space available.

In accordance with the provisions set forth in Section 552b(c)(6), Title 5, U.S. Code and Section 10(d) of Public Law 92-463, the meeting will be closed to the public on November 18, 1979, from 9:00 p.m. to recess, and from 8:30 a.m. on November 19, 1979 to adjournment on November 20, 1979; for the review, discussion and evaluation of an individual grant application. The application and the discussions could reveal personal information concerning individuals associated with the application, disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Mr. York Onnen, Chief, Public Inquiries and Reports Branch, NHLBI, National Institutes of Health, Building 31, Room 4A-21, phone (301) 496-4236, will provide summaries of the meeting and rosters of the committee members. Dr. Fred P. Heydrick, Chief, Research Contracts Review Section, Division of Extramural Affairs, NHLBI, Westwood Building, Room 548B, phone (301) 496-7363, will furnish substantive program information.

(Catalog of Federal Domestic Assistance Program No. 13.837, National Institutes of Health)

Dated: October 1, 1979.

Suzanne L. Fremeau,

Committee Management Officer, NIH.

[FR Doc. 79-30867 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-03-M

General Research Support Review Committee; Meeting

Pursuant to Public Law 92-463, notice is hereby given of the meeting of the General Research Support Review Committee, Division of Research Resources, National Institutes of Health, November 15, 16, 17, 1979. The meeting will be held in Conference Room 9, Building 31, 9000 Rockville Pike, Bethesda, Maryland 20205.

The meeting will be open to the public on November 15 from 9:00 a.m. to 12:30 p.m., for the discussion of administrative matters relating to the Biomedical Research Support Program and the Minority Biomedical Support Program. Attendance by the public will be limited to space available.

In accordance with the provisions set forth in Sections 552b(c)(4) and 552b(c)(6), Title 5, U.S. Code and Section 10(d) of Pub. L. 92-463, the meeting will be closed to the public on November 15, 1979, from 1:30 p.m. to 5:00 p.m., on November 16, 1979, from 8:30 a.m. to 5:00 p.m., and on November 17, 1979, from 8:30 a.m. to adjournment, for the review, discussion, and evaluation of individual grant applications. These applications and the discussions could reveal confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the applications, disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Mr. James Augustine, Information Officer, Division of Research Resources, Room 5B13, Bldg. 31, National Institutes of Health, Bethesda, Maryland, 20205, (301) 496-5545, will provide summaries of the meeting and rosters of the Committee members. Dr. Michael A. Oxman, Executive Secretary, General Research Support Review Committee, Room 5B25, Bldg. 31, National Institutes of Health, Bethesda, Maryland 20205, (301) 496-6743, will furnish substantive program information.

(Catalog of Federal Domestic Assistance Programs No. 13,337, National Institutes of Health)

Dated: October 1, 1979.

Suzanne L. Fremeau,

Committee Management Officer, National Institutes of Health.

[FR Doc. 79-30863 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-03-M

National Advisory Dental Research Council; Meeting

Pursuant to Public Law 92-463, notice is hereby given of the meeting of the National Advisory Dental Research Council, National Institute of Dental Research, on November 15-16, 1979, in Conference Room 10, Building 31-C, National Institutes of Health, Bethesda, Maryland. This meeting will be open to the public from 9:00 a.m. to adjournment on November 16 for general discussion and program presentations. Attendance by the public will be limited to space available.

In accordance with the provisions set forth in Sections 552b(c)(4) and 552b(c)(6), Title 5, U.S. Code and Section 10(d) of Public Law 92-463, the meeting of the Council will be closed to the public on November 15 from 9:00 a.m. to adjournment for the review, discussion and evaluation of individual grant applications. These applications and the discussions could reveal confidential trade secrets or commercial property such as patentable materials, and personal information concerning individuals associated with the applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Mrs. Dorothy Costinett, Committee Management Assistant, National Institute of Dental Research, National Institutes of Health, Building 31-C, Room 2C36, Bethesda, MD 20205, (phone 301 496-7658) will furnish rosters of committee members, a summary of the meeting, and other information pertaining to the meeting.

Dated: October 1, 1979.

Suzanne L. Fremeau,

Committee Management Officer, NIH.

(Catalog of Federal Domestic Assistance Program Nos. 13-840 through 13-845, and 13-878, National Institutes of Health.)

[FR Doc. 79-30888 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-03-M

National Advisory Research Resources Council; Meeting

Pursuant to Public Law 92-463, notice is hereby given of the meeting of the National Advisory Research Resources Council, Division of Research Resources (DRR), October 24-26, 1979, at the American College of Cardiology, 9111 Old Georgetown Road, Bethesda, MD 20014, and Rooms 5B03, 5B35, 5B39, 5B51, and 5B59, Bldg. 31, National Institutes of Health, Bethesda, MD 20205.

The meeting will convene at 9:00 a.m. on October 24, at the American College of Cardiology, for the conduct of Council business, including a report by the Director, DRR, a report by the Deputy Director, DRR, a presentation by a member of the Council entitled, "Women and the Urge to Learn," and a discussion of the procedure for reviewing the Divisional Five-Year Plan. At 1:00 p.m. until recess, the five Program Work Groups of the Council will convene in Bldg. 31 as follows, to deliberate on issues relating to their respective programs: Animal Resources Program Work Group in Room 5B59; Biomedical Research Support Work Group in Room 5B51; Biotechnology Resources Program Work Group in Room 5B39; Minority Biomedical Support Program Work Group in Room 5B35; and General Clinical Research Centers Program Work Group in Room 5B03. On October 25, the Council will reconvene at the American College of Cardiology from 9:00 a.m. to recess, for discussions and recommendations relating to the DRR Five-Year Plan.

The meetings of October 24 and 25, will be open to the public, limited to space available.

In accordance with provisions set forth in Sections 552b(c)(4) and 552b(c)(6), Title 5, U.S. Code and Section 10(d) of Pub. L. 92-463, the meeting of October 26, 1979, to be held at the American College of Cardiology, will be closed to the public from 9:00 a.m. to adjournment for the review, discussion, and evaluation of individual grant applications. These applications and the discussions could reveal confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the applications, disclosure of which would constitute a clearly unwarranted invasion of personal property.

Mr. James Augustine, Information Officer, Division of Research Resources, Room 5B13, Bldg. 31, National Institutes of Health, Bethesda, MD 20205, 301-496-5545, will provide summaries of the meeting and rosters of the Council members. Dr. James F. O'Donnell, Deputy Director, Division of Research Resources, Room 5B03, Bldg. 31, National Institutes of Health, Bethesda, MD 20205, 301-496-6023, will furnish substantive program information and will receive any comments pertaining to this announcement.

(Catalog of Federal Domestic Assistance Program Nos. 13.306; 13.333; 13.337; 13.371; 13.375; National Institutes of Health.)

Dated: September 27, 1979.

Suzanne L. Fremeau,

Committee Management Officer, National Institutes of Health.

[FR Doc. 79-30861 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-08-M

Minority Access to Research Careers Review Committee; Meeting

Pursuant to Pub. L. 92-463, notice is hereby given of the meeting of the Minority Access to Research Careers Review Committee, National Institute of General Medical Sciences, on November 8, 1979, 8:45 a.m., National Institutes of Health, Building 31-C, Conference Room 7.

This meeting will be open to the public on November 8, 8:45 a.m. to 10:45 a.m. The meeting will consist of opening remarks and discussion of procedural matters. Attendance by the public will be limited to space available.

In accordance with provisions set forth in Title 5, U.S. Code 552b(c)(6), the meeting will be closed to the public on November 8 from 10:45 a.m., until adjournment, for the scientific review of institutional and individual grant applications. These applications and the discussions could reveal personal information concerning individuals associated with the applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Mr. Paul Deming, Public Information Officer, NIGMS, Westwood Building, Room 9A-10, 5333 Westbard Avenue, Bethesda, Maryland 20205, telephone (301) 496-7301, will furnish summary minutes of the meeting and a roster of committee members.

Substantive program information may be obtained from Dr. Charles Miller, Acting Executive Secretary, Westwood Building, Room 950, Bethesda, Maryland 20205, telephone (301) 496-7125.

(Catalog of Federal Domestic Assistance Program 13.880, General Medical Sciences)

Dated: October 1, 1979.

Suzanne L. Fremeau,

Committee Management Officer, NIH.

[FR Doc. 79-30870 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-08-M

NIDR Special Grants Review Committee; Meeting

Pursuant to Public Law 92-463, notice is hereby given of the meeting of the National Institute of Dental Research Special Grants Review Committee, on November 6-7, 1979, in Conference Room 8, Building 31-C, National Institutes of Health, Bethesda, Maryland. This meeting will be open to the public from 9:00 a.m. to 10:30 a.m. on November 6, 1979, to discuss program policies and issues. Attendance by the public is limited to space available.

In accordance with provisions set forth in sections 552b(c)(4) and 552b(c)6, Title 5, U.S. Code and Section 10(d) of Public Law 92-463, the meeting will be closed to the public from 10:30 a.m. on November 6, 1979, to adjournment on November 7, 1979, for the review, discussion and evaluation of individual grant applications. These applications and the discussions could reveal confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Dr. Emil L. Rigg, Executive Secretary, NIDR Special Grants Review Committee, National Institute of Dental Research, National Institutes of Health, Westwood Building, Room 504, Bethesda, MD 20205, (telephone 301 496-7658) will provide summaries of meeting, rosters of committee members, and substantive program information.

(Catalog of Federal Domestic Assistance Programs Nos. 13-840 through 13-845, and 13-878, National Institutes of Health.)

Dated: October 1, 1979.

Suzanne L. Fremeau,

Committee Management Officer, NIH.

[FR Doc. 79-30869 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-08-M

Pharmacology-Toxicology Review Committee; Meeting

Pursuant to Public Law 92-463, notice is hereby given of the meeting of the Pharmacology-Toxicology Review Committee, National Institute of General Medical Sciences, November 15-16, 1979, National Institutes of Health, Building 31C, Conference Room 7, Bethesda, Maryland.

This meeting will be open to the public on November 15 from 8:30 a.m. to 9:30 a.m. for opening remarks and general administrative business. Attendance by the public will be limited to space available.

In accordance with provisions set forth in Title 5, U.S. Code 552b(c)(6), the meeting will be closed to the public on November 15 from 9:30 a.m. to 5:00 p.m. and on November 16 from 8:30 a.m. to 5:00 p.m. or adjournment for the review, discussion, and evaluation of individual grant applications. These applications and the discussions could reveal personal information concerning individuals associated with the applications, disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Mr. Paul Deming, Public Information Officer, NIGMS, Westwood Building, Room 9A12, Bethesda, Maryland 20205, Telephone: 301-496-7301, will provide a summary of the meeting and a roster of committee members.

Substantive program information may be obtained from Dr. Martha Panitch, Executive Secretary, Pharmacology-Toxicology Review Committee, National Institute of General Medical Sciences, Westwood Building, Room 953, Bethesda, Maryland, Telephone: 301-496-7585.

(Catalog of Federal Domestic Assistance Program 13-859, Pharmacology-Toxicology Program, National Institute of General Medical Sciences, National Institutes of Health)

Dated: October 1, 1979.

Suzanne L. Fremeau,

Committee Management Officer, NIH.

[FR Doc. 79-30871 Filed 10-4-79; 8:45 am]

BILLING CODE 4110-08-M

Vision Research Program Committee; Meeting

Pursuant to Public Law 92-463, notice is hereby given of the meeting of the Vision Reserach Program Committee, National Eye Institute, November 15, 1979, Building 31, C Wing, Conference Room 8, National Institutes of Health, Bethesda, Maryland.

This meeting will be open to the public on Thursday, November 15, from 8:30 a.m. to 9:30 a.m. for opening remarks. Attendance by the public will be limited to space available.

In accordance with provisions set forth in Section 552b(c)(4) and 552(c)(6), Title 5, U.S. Code and Section 10(d) of Pub. L. 92-463, the meeting will be closed to the public from 9:30 a.m. on November 15 until adjournment on November 15 for the review, discussion and evaluation of individual grant applications. These applications and the discussions could reveal confidential trade secrets or commercial property as patentable material, and personal information concerning individuals associated with the applications, disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Mr. Julian Morris, Chief, Office of Program Planning and Scientific Reporting, National Eye Institute, Building 31, Room 6A-25, National Institutes of Health, Bethesda, Maryland 20205 (telephone: 301/496-5248) will furnish summaries of the meeting and rosters of committee members.

Dr. Catherine Henley, Review and Special Projects Officer, Extramural and Collaborative Programs, National Eye Institute, Building 31, Room 6A-06, National Institutes of Health, Bethesda, Maryland 20205 (telephone: 301/496-5561) will furnish substantive program information.

(Catalog of Federal Domestic Assistance Program Nos. 13.867, 13.868, 13.869, 13.870, and 13.871, National Institutes of Health.)

Dated: October 1, 1979.

Suzanne L. Fremeau,

Committee Management Officer, NIH.

[FR Doc. 79-30865 Filed 10-5-79; 8:45 am]

BILLING CODE 4110-08-M

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

Arizona; Hualapai-Aquarius Planning Area; Preparation of Management Framework Plan

The Phoenix District Office is in the process of preparing a Management Framework (Land-Use) Plan for the Hualapai-Aquarius Planning Area, in southern Mohave County, Arizona. The area extends from Kingman south to the Bill Williams River, including the Hualapai Mountain, and then east to near Bagdad, Arizona, including the southern portion of the Aquarius Mountains.

The following resource disciplines will be represented on the interdisciplinary planning team: Botany, Range Management, Earth Science, Minerals, Geology, Wildlife Biology, Archaeology, Outdoor Recreation Planning, Land-Use Planning, Economics, Sociology, and Natural Resource Management.

The planning effort began in October 1978 with a public meeting in Kingman; the purpose of the meeting was to inform the public of the planning process and to obtain public comment on key issues or problems that needed to be addressed in the planning area.

Natural resource inventories and socio-economic studies were also initiated last October to be used as baseline data in subsequent environmental analyses and land-use proposals. Resource data is currently being analyzed in an effort to describe resource existance, conditions, and potential uses. Resource workshop groups will be organized to provide comment and input to the analysis. Workshop members will be composed of representatives from local, state, and federal government offices, private and public agencies or organizations, industries and business concerns, and concerned citizens. Eleven workshop groups will be established: Land Use/Transportation/Utilities; Minerals/Energy Development; Livestock Grazing; Wild Burros; Wildlife Habitat; Threatened and Endangered Plants; Wilderness; Off-Road Vehicles; General Recreation; Cultural Resources; and Soil & Water Conservation. These same Workshop Groups will also assist in development of resource, use objectives, and conflict analysis between proposed competing resource uses.

Open-house public meetings will also be held to obtain additional public comment to resource use proposals. These meetings will be held in Kingman, Bagdad, Wikieup, and Phoneix, Arizona. Further specific information (times, dates, and locations) concerning workshop and open house meetings will be provided at a later date.

Information generated by the above process will be considered as the "Scoping" effort for subsequent Environmental Statements as presented in 40 CFR 1501.7

For further information about the planning or environmental statement process contact: Frank Splendoria, Phoenix District Office, BLM, 2929 West Clarendon Avenue, Phoenix, Arizona 85017; (602) 261-4231.

Planning and environmental documents eventually developed will be available at the above address, and the Kingman Resource Area Office, 2475 Beverly, Kingman, Arizona 86401; (602) 757-4011.

W. K. Barker,

District Manager.

September 28, 1979.

[FR Doc. 79-30845 Filed 10-4-79; 8:45 am]

BILLING CODE 4310-84-M

List of Restricted Joint Bidders

Pursuant to the authority vested in the Director of the Bureau of Land Management by the Joint Bidding provisions of 43 CFR 3316.3, the following companies shall be restricted from bidding jointly with any other company on this same list at Outer Continental Shelf oil and gas lease sales held during the bidding period of November 1, 1979, through April 30, 1980. BP Alaska Exploration Inc., and Sohio Natural Resources Company are listed together as one Restricted Joint Bidder; they may bid with each other, but not with any other company on this list:

Amoco Production Company
BP Alaska Exploration Inc., and Sohio Natural Resources Company
Chevron U.S.A. Inc.
Exxon Corporation
Mobil Oil Corporation
Mobil Oil Exploration and Producing Southeast, Inc.
Shell Oil Company
Standard Oil Company of California
Texaco Inc.

Ed Hastey,
Associate Director, Bureau of Land Management.
October 2, 1979.

[FR Doc. 79-30843 Filed 10-4-79; 8:45 am]
BILLING CODE 4310-84-M

Colorado and Wyoming; Intent To Hold Public Scoping Meetings and To Prepare a Regional Environmental Impact Statement for the Proposed Leasing of Federal Coal in the Green River-Hams Fork Region

AGENCY: Bureau of Land Management, Interior.

ACTION: Public meetings and notice to prepare an EIS.

SUMMARY: This notice advises the public that the Bureau of Land Management intends to hold meetings to gather information and seek assistance in defining the range of issues and concerns for the preparation of a regional environmental impact statement (EIS) for the proposed leasing of Federal coal within the Green River-Hams Fork coal production region. This proposed leasing is needed to meet the Department of the Interior's Federal leasing target and the Department of Energy regional production goal, in accordance with the Federal coal management program as announced by the Secretary on June 4, 1979. This notice is made in accordance with the National Environmental Policy Act (NEPA) and the Council on Environmental Quality 40 CFR 1501.7 regulation to obtain suggestions and information from other agencies and the public on the scope of issues to be addressed in the EIS. Comments and participation in this scoping process are solicited.

Public meetings will be held in Denver and Craig, Colorado; and in Rawlins and Cheyenne, Wyoming. Oral presentations and submissions of written comments will be received at the meetings.

A general description of the coal lease tracts that may be selected for the proposed action and alternative for environmental impact analysis in the regional EIS is provided below.

DATES: Additional written comments may be received through November 8, 1979. Public meetings will be held on October 22, October 23, October 24 and October 25, 1979.

ADDRESSES: Comments should be addresses to: Dan Martin, Regional Coal EIS Team Leader, Craig District Office, Bureau of Land Management, P.O. Box 248, 455 Emerson Street, Craig, Colorado 81625.

The locations of the public meetings are listed below.

FOR FURTHER INFORMATION CONTACT: Dan Martin (303) 824-3417.

SUPPLEMENTAL INFORMATION: The tracts proposed for leasing are within the BLM Williams Fork Planning Unit in Colorado and the Hanna and Overland Planning Units in Wyoming. A map defining the location of these tracts is available for review at the Craig District Office at the address given above and will also be available at the public meetings.

The location of these tracts is available for review at the Craig District Office at the address given above and will also be available at the public meetings.

TRACTS DELINEATED. The following preliminary tracts are under consideration for leasing in 1981. All acreages and tonnages are preliminary and subject to change.

Tract name	General location	Approximate acreage	Million tons of coal in-place
COLORADO			
1. Bell Rock	About 8 miles southwest of Craig, CO, adjacent to the existing Empire Energy underground mine.	434	42.00
2. Danforth Hills I	About 13 miles north-northeast of Meeker, CO, adjacent to the Colowyo mine.	876	51.60
3. Danforth Hills II	Along the Moffat-Rio Blanco County line, 13 miles north-northeast of Meeker, CO.	5,680	111.74
4. Grassy Creek	About 10 miles southeast of Hayden, CO, southwest of Grassy Gap.	580	9.00
5. Hayden Gulch	West of Hayden Gulch about 10 miles south-southwest of Hayden, CO.	5,860	97.27
6. Horse Gulch	About 15 miles west-southwest of Craig, CO, north of the Yampa River.	4,400	4.00
7. Iles Mountain	On the north slope of Iles Mountain about 12 miles southwest of Craig, CO.	5,240	94.33
8. Lay	About 20 miles west of Craig, CO. and 4 miles north of Lay.	12,920	90.50
9. Pinnacle	About 15 miles southwest of Steamboat Springs, CO. adjacent to the Energy Fuels mine.	350	1.10
10. Williams Fork Mountains	In the Williams Fork Mountains about 15 miles southeast of Craig, CO.	15,893	46.46
WYOMING			
1. China	25 to 31 miles southwest of Rawlins, WY, 4 to 9 miles east of highwya 789, north of Doty Mountain.	3,270	139.30
2. Medicine Bow	10 to 16 miles northwest of Hanna, WY, east of Seminoe Reservoir.	15,200	80.70
3. Red Rim	Extends from south of I-80 about 8 miles west of Rawlins for about 18 miles southwest.	14,000	50.90
4. Rosebud	About 6 to 8 miles northeast of Hanna, WY	4,960	18.26
5. Seminoe II	Extends due north of Hanna, WY over a distance of 7 miles and is 2 to 4 miles wide.	10,840	29.30

The alternatives that have been tentatively identified include the following: to modify the scheduling of lease tracts within the 2-year period; to modify the combination of tracts considered as the proposed action and alternatives; to delay or defer tract sales; and to not offer Federal coal lease tracts for competitive sale. Prior to the preparation of the EIS, the tracts identified in accordance with the Federal coal management regulations will be ranked, selected, and scheduled by a Regional Coal Team pursuant to 43 CFR 3420.4, and recommendations will be made to the Director of the Bureau of Land Management and the Secretary of the Interior. The draft EIS is scheduled to be made available to the public by April 30, 1980.

DATE, TIME AND LOCATION OF SESSIONS: The public scoping meetings to assist in defining significant environmental issues and concerns for the preparation of a regional EIS for proposed Federal coal leasing are being combined with the public hearings to obtain comments on the Federal coal leasing target. Accordingly, each general session will consist of a leasing target hearing followed by a scoping meeting. These combined sessions will be held as follows:

Place	Date	Time	Address
Denver, CO	October 22, 1979	1 p.m.	Auditorium, Building 56, Denver Federal Center, West 6th Ave. and Kipling, Denver, CO.
Craig, CO	October 23, 1979	7 p.m.	Auditorium, Moffatt County, Courthouse, 221 Victory Way, Craig, CO.
Rawlins, WY	October 24, 1979	1 p.m.	Conference Room, Holiday Inn, 1801 East Cedar, Rawlins, WY.
Cheyenne, WY	October 25, 1979	7 p.m.	Cheyenne Club Room, West, Hitching Post Inn, 1600 West Lincoln Way, Cheyenne, WY.

Possible major issues as a result of further coal development in the Green River-Hams Fork region are socio-economic and air quality values. A separate Federal Register notice discusses the public hearings concerning the regional coal leasing target.

The agenda of these meetings will be as follows:

1. Introduction:

a. Purpose and intent of meeting;

b. Description of previously defined issues identified during pre-analysis to be considered in the EIS;

c. Alternatives to the proposed action as presently considered in the EIS process, including not offering Federal coal lease tracts for competitive sales;

d. Information available from the BLM offices for the use of the public in commenting, including names and addresses where information and comments can be submitted.

2. Solicitation of public comment, recommendations, and issues of major concern to be considered and addressed in the ranking, selection, scheduling, and EIS impact analysis process.

The environmental review of this project will be conducted in accordance wih the requirements of the National Environmental Policy Act of 1969, Council on Environmental Quality Regulations, other required Federal laws and regulations, and Department of the Interior policy and procedures for compliance with those regulations.

Ed Hastey,

Associate Director, Bureau of Land Management.

October 2, 1979.

[FR Doc. 79-31025 Filed 10-4-79; 8:45 am]

BILLING CODE 4310-84-M

Colorado and Wyoming; Intent To Hold Public Hearings and the Opening of a 30-Day Comment Period on the Federal Coal Leasing Target for the Green River-Hams Fork Region

AGENCY: Bureau of Land Management, Interior.

ACTION: Public hearings and opening of 30-day comment period.

SUMMARY: This notice advises the public that pursuant to 43 CFR 3420.3-2(d) the Federal Regional Coal Team intends to hold hearings in order to assist the Secretary of the Interior in establishing a regional Federal coal leasing target for the Green River-Hams Fork coal production region which covers portions of the States of Colorado and Wyoming.

Public hearings will be held in Denver and Craig, Colorado; and in Rawlins and Cheyenne, Wyoming. Oral testimony and submissions of written comments will be received at the hearings.

The Secretary of the Interior, as part of his announcement of a new Federal coal management program on June 4, 1979, set a tentative regional Federal leasing target of 531 million tons for the Green River-Hams Fork region with proposed lease sales to occur over a 2-year period beginning January 1981. Information received since June 4 has resulted in a reduction of the preliminary leasing target to 321 million tons as described under Supplemental Information. Individuals wishing to comment orally at the public heaings are asked to provide written copies of their remarks. Information or additional comments not presented at the hearings should be sent to the Chairman, Regional Coal Team at the address given below. Written comments on the leasing target will be accepted from those unable to attend the public hearings.

DATES: Written comments will be received through November 8, 1979. Public hearings will be held on October 22, October 23, October 24, and October 25, 1979.

ADDRESSES: Comments should be addressed to: Gary J. Wicks, Utah State Director, Bureau of Land Management, Chairman, Regional Coal Team, University Club Building, 136 South Temple, Salt Lake City, Utah 84111.

The locations of the public hearings are listed below.

FOR FURTHER INFORMATION CONTACT: Gary J. Wicks (801) 524-5311.

SUPPLEMENTAL INFORMATION: The leasing target for the Green River-Hams Fork Region is based upon the difference between the Department of Energy's (DOE) projections of total coal production and the Department of the Interior's estimate of production from mines within the region not dependent upon new Federal coal leasing for continued production. This difference in annual tonnage is converted to tons in-place using estimates of mine life, the Federal share of coal ownership in the region, and the expected percentage of in-place coal.

DOE projected coal production in 1985 and 1990 for three sets of coal demand assumptions—high, medium and low. These scenarios provide production projections that bracket the range of reasonable expectations. The Secretary in his June 4, 1979, decisions chose preliminary leasing targets for the Green River-Hams Fork Region to meet DOE's production estimate under the medium scenario.

The medium DOE projections for Colorado are 24.7 million tons in 1985 and 30.3 million tons in 1990. Because Colorado encompasses parts of four production regions, the DOE projections for the State had to be disaggregated into regions.

The disaggregation for the Green River-Hams Fork Region in Colorado resulted in production projections of 14.4 million tons in 1985 and 16.9 million tons in 1990.

No disaggregation was required for production projections for the Wyoming portion of the Green River-Hams Fork Region because the model used by DOE to make the projections was designed to specifically project for the area in question. Specifically, the DOE medium projections for the Wyoming portions of the Green River-Hams Fork Region are 59.2 million tons in 1985 and 85.6 million tons in 1990. Summing the projections for the portions of the two States results in production projections for the entire region of 73.6 million tons in 1985 and 102.5 million tons in 1990.

The Secretary in his June 4, 1979, decisions chose to lease to meet 1987 projections in the region. Straight line interpolation between the 1985 and 1990 projections was used to calculate the 1987 projection of 85.2 million tons.

Production estimates from all mines including existing Federal leases with approved mine plans or with mine plans pending approval were then subtracted from the 1987 production estimate. The following table shows the production estimates from individual mines in this category.

County	Mine name	1985, 1990 production estimate (100 tons/yr.)	Lessee
Moffat	Colowyo	3000.00	Colowyo Coal Co.
	Trapper	2000.00	Utah International Inc.
	Wise Hill 5, 5A, 9	444.20	Empire Energy Corp.
	Apex	100.00	Sunland Coal Co.
	Edna	1000.00	Gulf Oil Corp.
	Energy Fuels No. 1, 2, 3	4000.00	Energy Fuels Corp.
	Seneca 2-W	900.00	Material Service Corp.
Carbon	Hanna South	508.53	Ark Land Co.
	Medicine Bow	3000.00	Medicine Bow Coal Co.
	Rosebud	2300.00	Rosebud Coal Sales Co.
	Seminoe No. 1	2000.00	Ark Land Co.
	Seminoe No. 2	2500.00	Ark Land Co.
	Vanguard No. 2	1000.00	Energy Dev. Co.
Lincoln	North Block	1400.00	Kemmerer Coal Co.
	South Block	3500.00	Kemmerer Coal Co.
	Twin Creek	2500.00	Rocky Mtn. Energy Co.
	Skull Point	1200.00	FMC Corp.
Sublette	Cottonwood	20.00	George N. Hendon
Sweetwater	Black Butte	6300.00	Black Butte Coal Co.
	Cherokee	5000.00	Resource Dev. Co.
	Jim Bridger	7150.00	Bridger Coal Co.
	Long Canyon	2000.00	Sunoco Energy Develop.
	Rainbow	200.00	Sweetwater Resource, Inc.
	Stansbury	1200.00	Stansbury Coal Co.
Uinta	South Haystack	3000.00	Cumberland Coal Co.
Total		56222.73	

Also subtracted from the 1987 total production projection was the Department of Energy's estimate of production from mines involving wholely non-Federal coal as shown in the following table.

County	Mine name	1985, 1990 production estimate (1,000 tons/yr.)	Owner
Carbon	Atlantic Rim	2,500	Rocky Mountain Energy.
Hot Springs	Grass Creek	700	Northwest Resources.
Jackson	Marr	400	Kerr Coal Co.
	Canadian	300	Sigma-Consol
Moffat	EFC 4	1,500	Energy Fuels Corp.
Routt	Hayden Gulch	1,000	W.R. Grace/Hanna.
	Meadows No. 1	200	A.T. Massey Co.
Total		6,600	

Finally, the Department subtracted production estimates of existing Federal leases which have no mine plans approved or pending approval, but which, in the best judgment of the U.S. Geological Survey, would likely be in production by June 1986. The 13 existing leases in this category encompass 157 million tons of recoverable reserves. Assuming a mine life of 30 years, these leases could produce about 5.2 million tons per year.

Subtracting the three categories of coal supply from the 1987 production estimate results in an unsatisfied demand of 17.2 million tons. This estimate of annual production shortfall was converted to coal in-place which could be leased to satisfy this shortfall by multiplying by a 30-year mine life; by 0.56, representing the average 56 percent Federal ownership of coal within the Known Recoverable Coal Resource Areas within the Green River-Hams Fork Region; and dividing by 0.9, representing the 90 percent recovery of coal from surface operations. The result of this calculation is a leasing target of 321 million tons.

Reviewers should note that this number is lower by 210 million tons than the preliminary target for the region presented in the Secretarial Issue Document in June 1979. This difference is largely due to the addition of production from several mines in both Wyoming and Colorado to the category of existing Federal leases with approved or pending mine plans.

Other points which could affect any final leasing decisions in the region are noted below:

1. Commonwealth-Edison has a lease application in Carbon County, Wyoming, which is being processed as a hardship case under 43 CFR 3421.1-6. Should this application proceed successfully, an additional 5 million tons per year could be added to the category of existing leases with approved or pending mine plans.

2. No consideration was given to any production potential from the 26 Preference Right Lease Applications (PRLA's) within the Green River-Hams Fork Region because of the current uncertainty of timing and quantity of such production. Should this uncertainty lessen as the PRLA's are processed, the leasing target or tract scheduling will be adjusted accordingly.

3. The leasing target assumes that a significant portion of leased coal will be in production by 1985—a four year lead time—and that a six-year lead time applies to the balance of the leasing target. Should these estimates of lead time be altered prior to tract scheduling, the target could be adjusted accordingly.

4. Coal lease applications that have been filed that meet production maintenance or bypass situations do not count against the leasing target.

5. The 56 percent Federal ownership datum could be revised after examination of ownership patterns in mining units associated with specific tracts.

6. The assumption of a 90 percent recovery factor will be adjusted as more tract specific information is developed during coal activity planning. This is especially important for tracts for which production will be mined by underground methods.

Reviewers are encouraged to comment on all aspects of the derivation of the preliminary leasing target. The Department is especially interested in the accuracy of the production estimates for the individual mines listed in the tables above and whether any mining operations should be added or deleted. Comments on the availability of transportation to any of the listed mines are encouraged as are comments on the lead time between lease sale and mature production and on any margin of error which might be considered in setting final leasing targets. Finally, the Department solicits any information relating to the demand for coal from the region for production of synthetic fuels.

DATE, TIME AND LOCATION OF SESSIONS: The public hearings to obtain comments on the Federal coal leasing target for the region are being combined with the public scoping meetings concerning the preparation of the regional coal environmental impact statement (EIS). Accordingly, each general session will consist of a leasing target hearing followed by a scoping meeting. These combined sessions will be held as follows:

Place	Date	Time	Address
Denver, CO	October 22, 1979	1 p.m.	Auditorium, Building 56, Denver Federal Center, West 6th Ave. and Kipling, Denver, CO.
Craig, CO	October 23, 1979	7 p.m.	Auditorium, Moffat County Courthouse, 221 Victory Way, Craig, CO.
Rawlins, WY	October 24, 1979	1 p.m.	Conference Room, Holiday Inn, 1801 East Cedar, Rawlins, WY.
Cheyenne, WY	October 25, 1979	7 p.m.	Cheyenne Club Room West, Hitching Post Inn, 1600 West Lincoln Way, Cheyenne, WY.

With regard to the Denver session, if all those wishing to testify at the target hearings have not been heard by 4:00 PM, this portion of the session will be recessed and reconvened at 7:00 PM. If there are persons wishing to appear only at an evening session, they should notify Gary J. Wicks at the above address by the close of business October 19, 1979. A separate Federal Register notice discusses the public meetings concerning the preparation of the EIS.

The agenda of these hearings is as follows:

1. Introduction

a. Purpose of holding the public hearing and obtaining comments on leasing target

b. Description of the relationship of this process with NEPA

c. Brief description of the Federal Coal Management Program

d. Description of the role of the regional coal team in the process

e. Description of derivation of preliminary or tentative leasing target

2. Obtaining of public comments and recommendations on the regional Federal coal leasing targets.

3. Close.

Ed Hastey,

Director, Bureau of Land Management.

October 2, 1979.

[FR Doc. 79-31024 Filed 10-4-79; 8:45 am]

BILLING CODE 4310-84-M

[AA-6981-A and AA-6981-B]

Alaska Native Claims Selection

On November 19, 1974, Haida Corporation, for the Native village of Hydaburg, filed selection application AA-6981-A, and on November 26, 1974, filed selection application AA-6981-B, under the provisions of Sec. 16(b) of the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 708; 43 U.S.C. 1601, 1615(b) (1976)) (ANCSA), for the surface estate of certain lands in the vicinity of Hydaburg.

As to the lands described below, the applications, as amended, are properly filed and meet the requirements of the Alaska Native Claims Settlement Act and of the regulations issued pursuant thereto. These lands do not include any lawful entry perfected under or being maintained in compliance with laws leading to acquisition of title.

In view of the foregoing, the surface estate of the following described lands, selected pursuant to Sec. 12(a) of ANCSA, aggregating approximately 20,810.16 acres, is considered proper for acquisition by Haida Corporation and is hereby approved for conveyance pursuant to Sec. 14(a) of ANCSA:

The following described lands may be patented:

U.S. Survey 1939 Situate in Sukkwan Strait, Alaska.

Containing 10.26 acres.

Copper River Meridian, Alaska

T. 77 S. R. 83 E. (Partially Surveyed),
Sec. 1, lots 1 to 8, inclusive, E½NE¼;
Sec. 2, lots 1, 2 and 3;
Sec. 3, lots 1 to 15, inclusive, NW¼SW¼;
Sec. 4, lots 1 to 14, inclusive, SE¼SW¼;
Sec. 5, lots 1 to 16, inclusive, N½NW¼;
Sec. 6, lots 1 to 14, inclusive, N½NE¼, NE¼NW¼;
Sec. 7, lots 1 to 8, inclusive;
Sec. 8, lots 1 to 17, inclusive, E½E½;
Sec. 9, lots 1 to 6, inclusive, N½NE¼, W½;
Sec. 10, lots 1 to 9, inclusive, W½W½;
Sec. 11, lots 1 to 5, inclusive;
Sec. 12, lots 1 to 12, inclusive;
Sec. 13, lots 1 to 12, inclusive;
Sec. 14, lots 1 to 7, inclusive;
Sec. 15, lots 1 to 8, inclusive, N½NW¼, SE¼NW¼, SE¼SW¼;
Sec. 16, lots 1, to 2 and 3, inclusive, NE¼NE¼, W½E½, W½;
Sec. 17, lots 1 to 9, inclusive, E½E½;
Sec. 20, lots 1 to 11, inclusive, E½NE¼, NE¼SE¼;
Sec. 21, lots 1 to 8, inclusive, NW¼;
Sec. 22, lots 1 to 11, inclusive, and lot 15;
Sec. 23, lots 1 to 9, inclusive, SE¼SE¼;
Sec. 24, lots 1, 2 and 3, NE¼, NE¼NW¼, S½NW¼, SW¼, W½SE¼;
Sec. 25, E½, NW¼NW¼;
Sec. 26, lots 1, 2, 3 and 4, N½NE¼;
Sec. 27, lots 1 and 5 to 12, inclusive, S½SE¼;
Sec. 34, lots 1 to 11, inclusive;
Sec. 36, N½NE¼;
Containing 7,632.50 acres.

T. 77 S., R. 84 E. (Partially Surveyed),
Sec. 1, W½SW¼;
Sec. 2, S½NE¼, S½;
Sec. 3, S½;
Secs. 4, and 5, all;
Sec. 6, lots 1, 2, 3 and 4, E½, E½W½;
Sec. 7, lots 1 to 6, inclusive, NE¼, NE¼NW¼, E½SE¼;
Sec. 8 to 11, inclusive, all;
Sec. 12, NW¼NW¼;
Secs. 13 to 16, inclusive, all;
Sec. 17, lots 1 to 8, inclusive, E½ NW¼NW¼,SE¼SW¼;
Sec. 18, lots 1 to 12, inclusive;
Sec. 19, lots 1 to 13, inclusive;
Sec. 20, lots 1 to 7, inclusive, N½NE¼;
Sec. 21, lots 1, 2, 3 and 4, N½, E½SE¼, NW¼SE¼;
Sec. 22, N½NE¼, SW¼SW¼;
Sec. 24, lots 1 to 2, N½NE¼, NW¼;
Sec. 25, lots 3, 6 and 7, SE¼NW¼, W½SE¼;
Sec. 26, SE¼NE¼, S½SW¼, SE¼;
Sec. 27, lots 1 to 5, inclusive, W½NE¼, SE¼NE¼, N½NW¼, SE¼NW¼, E½SE¼;
Sec. 28 lots 1 to 5, inclusive;
Sec. 29, lots 1 to 6, inclusive, E½SW¼, S½SE¼;
Sec. 30, lots 1, 2 and 3, N½NE¼, E½NW¼;
Sec. 32, NE¼NE¼;
Sec. 33, lots 1 to 5, inclusive, N½SW¼;
Sec. 34, lot 1;
Sec. 35, lots 1 to 6, inclusive, N½NE¼, SE¼NE¼;
Sec. 36, lots 1 to 6, inclusive, N½, NE¼SW¼, N½SE¼.
Containing 13,009.40 acres.
Aggregating 20,652.16 acres.

The following described lands may be interim conveyed:

Copper River Meridian, Alaska

T. 77 S., R. 83 E. (Partially Surveyed),
Sec. 9, the unnamed lake;
Sec. 22, lots 12, to 13 and 14, excluding AA-20914 Goat Island Lighthouse, request for designation as Sec. 3(e), Alaska Native Claims Settlement Act;
Sec. 27, lots 2, 3 and 4, excluding AA-20914, Goat Island Lighthouse, request for designation as Sec. 3(e) Alaska Native Claims Settlement Act.
Containing approximately 133 acres.

T. 77 S., R. 84 E. *(Partially Surveyed),*
Sec. 24, the portion of Eek Lake falling within the N½ of the section.
Containing approximately 25 acres.
Aggregating approximately 158 acres.

The conveyance issued for the surface estate of the lands described above shall contain the following reservation to the United States:

The subsurface estate therein, and all rights, privileges, immunities, and appurtenances, of whatsoever nature, accruing unto said estate pursuant to the

Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 704; 43 U.S.C. 1601, 1613(f) (1976)) (ANCSA).

There are no easements to be reserved to the United States pursuant to Sec. 17(b) of ANCSA.

The grant of the above-described lands shall be subject to:

1. Issuance of a patent confirming the boundary description of the unsurveyed lands hereinabove granted after approval and filing by the Bureau of Land Management of the official plat of survey covering such lands;

2. Valid existing rights therein, if any, including but not limited to those created by any lease (including a lease issued under Sec. 6(g) of the Alaska Statehood Act of July 7, 1958 (72 Stat. 339, 341; 48 U.S.C. Ch. 2, Sec. 6(g) (1976))), contract, permit, right-of-way, or easement, and the right of the lessee, contractee, permittee, or grantee to the complete enjoyment of all rights, privileges, and benefits thereby granted to him. Further, pursuant to Sec. 17(b)(2) of the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 708; 43 U.S.C. 1601, 1616(b) (1976)) (ANCSA), any valid existing right recognized by ANCSA shall continue to have whatever right of access as is now provided for under existing law;

3. Requirements of Sec. 22(k) of the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 715; 43 U.S.C. 1601, 1621(k) (1976)), that, until December 18, 1983, the portion of the above-described lands located within the boundaries of a national forest shall be managed under the principles of sustained yield and under management practices for protection and enhancement of environmental quality no less stringent than such management practices on adjacent national forest lands; and

4. Requirements of Sec. 14(c) of the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 703; 43 U.S.C. 1601, 1613(c) (1976), that the grantee hereunder convey those portions, if any, of the lands hereinabove granted, as are prescribed in said section.

Haida Corporation is entitled to conveyance of 23,040 acres of land selected pursuant to Sec. 16(b) of ANCSA. Together with the lands herein approved, the total acreage conveyed or approved for conveyance is 20,810.16 acres. The remaining entitlement of approximately 2,229.84 acres will be conveyed at a later date.

Pursuant to Sec. 14(f) of ANCSA, conveyance to the subsurface estate of the lands described above shall be granted to Sealaska Corporation when conveyance is granted to Haida Corporation for the surface estate, and shall be subject to the same conditions as the surface conveyance.

There are no inland water bodies considered to be navigable within the above described lands.

In accordance with Departmental regulation 43 CFR 2650.7(d), notice of this decision is being published once in the Federal Register and once a week, for four (4) consecutive weeks, in the Ketchikan Daily News. Any party claiming a property interest in lands affected by this decision may appeal the decision to the Alaska Native Claims Appeal Board, P.O. Box 2433, Anchorage, Alaska 99510 with a copy served upon both the Bureau of Land Management, Alaska State Office, 701 C Street, Box 13, Anchorage, Alaska 99513 and the Regional Solicitor, Office of the Solicitor, 510 L Street, Suite 408, Anchorage, Alaska 99501, also:

1. Any party receiving service of this decision shall have 30 days from the receipt of this decision to file an appeal.

2. Any unknown parties, any parties unable to be located after reasonable efforts have been expended to locate, and any parties who failed or refused to sign the return receipt shall have until November 5, 1979 to file an appeal.

3. Any party known or unknown who may claim a property interest which is adversely affected by this decision shall be deemed to have waived those rights which were adversely affected unless an appeal is timely filed with the Alaska Native Claims Appeal Board.

To avoid summary dismissal of the appeal, there must be strict compliance with the regulations governing such appeals. Further information on the manner of and requirements for filing an appeal may be obtained from the Bureau of Land Management, 701 C Street, Box 13, Anchorage, Alaska 99513.

If an appeal is taken, the parties to be served with a copy of the notice of appeal are:

Haida Corporation, Box 89, Hydaburg, Alaska 99922.

Sealaksa Corporation, One Sealaska Plaza, Suite 400, Juneau, Alaska 99801.

Ramona M. Chinn,

Acting Chief, Branch of Adjudication.

[FR Doc. 79-30928 Filed 10-4-79; 8:45 am]

BILLING CODE 4310-84-M

[F-19155-16]

Alaska Native Claims Selection

On April 2, 1975, Doyon, Limited filed selection application F-19155-16, as amended, under the provisions of Sec. 12(c) of the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 701; 43 U.S.C. 1601, 1611(c) (1976)) (ANCSA), for the surface and subsurface estates of certain lands withdrawn pursuant to Sec. 11(a)(1) for the Native village of Kaltag. The application excluded the following water bodies as being navigable:

South Fork Nulato River;
Tsurotlurna Slough;
Yukon Creek.

As these are considered nonnavigable and as Sec. 12(c)(3) and 43 CFR 2652.3(c) require the region to select all available lands within the township, the beds of these water bodies are considered selected.

As to the lands described below, the application, as amended, is properly filed and meets the requirements of the Alaska Native Claims Settlement Act and of the regulations issued pursuant thereto. These lands do not include any lawful entry perfected under or being maintained in compliance with laws leading to acquisition of title.

In view of the foregoing, the surface and subsurface estates of the following described lands, selected pursuant to Sec. 12(c) of ANCSA, aggregating approximately 180,835 acres, are considered proper for acquisition by Doyon, Limited and are hereby approved for conveyance pursuant to Sec. 14(e) of ANCSA:

Kateel River Meridian Alaska (Unsurveyed)

T. 11 S., R. 1 W.,
Secs. 1 to 36, inclusive, all.
Containing approximately 22,932 acres.

T. 13 S., R. 1 W.,
Secs. 5 to 10, inclusive, all;
Secs. 15 to 22, inclusive, all;
Secs. 27 to 32, inclusive, all.
Containing approximately 12,548 acres.

T. 15 S., R. 1 W.,
Secs. 9, 10 and 11, all;
Secs. 14, 15 and 16, all;
Secs. 19 to 23, inclusive, all;
Secs. 26 to 35, inclusive, all.
Containing approximately 13,395 acres.

T. 12 S., R. 2 W.,
Secs. 2 to 11, inclusive, all;
Secs. 13 to 36 inclusive, all.
Containing approximately 21,724 acres.

T. 14 S., R. 2 W.,
Secs. 1 to 12, inclusive, all;
Secs. 15 to 20, inclusive, all;
Secs. 30, all;
Secs. 33 to 36, inclusive, all.
Containing approximately 14,565 acres.

T. 11 S., R. 1 E.,
Secs. 1 to 36, inclusive, all.
Containing approximately 21,932 acres.

T. 12 S., R. 2 E.,
Sec. 6, all;
Sec. 13, excluding Native allotment F-027522;
Secs. 23 to 26, inclusive, all;
Secs. 34, 35 and 36, all.
Containing approximately 5,729 acres.

T. 14 S., R. 2 E.,
Sec. 1, excluding Khotol River;
Secs. 2 to 10, inclusive, all;
Sec. 11, excluding Khotol River;

Sec. 12, excluding Native allotment F-17125 Parcel A and Khotol River;
Sec. 13, excluding Native allotment F-17125 Parcel A;
Secs. 14 and 15, excluding Khotol River;
Secs. 16 to 21, inclusive, all;
Secs. 22 and 23, excluding Khotol River;
Secs. 24, 25 and 26, all;
Secs. 27, 28 and 29, excluding Khotol River;
Sec. 30, all;
Secs. 31, 32 and 33, exluding Khotol River;
Secs. 34, 35 and 36, all.
Containing approximately 21,950 acres.

T. 13 S., R. 3 E.,
Secs. 1 to 36, inclusive, excluding Khotol River;
Containing approximately 22,128 acres.

T. 15 S., R. 3 E.,
Secs. 1 to 36, inclusive, all.
Containing approximately 22,932 acres.
Aggregating approximately 180,835 acres.

The conveyance issued for the surface and subsurface estates of the lands described above shall contain the following reservation to the United States:

Pursuant to Sec. 17(b) of the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 708; 43 U.S.C. 1601, 1616(b) (1976)), the following public easements, referenced by easement identification number (EIN) on the easement maps attached to this document, copies of which will be found in case file F-21779-16, are reserved to the United States. All easements are subject to applicable Federal, State, or Municipal corporation regulation. The following is a listing of uses allowed for each type of easement. Any uses which are not specifically listed are prohibited.

25 Foot Trail—The uses allowed on a twenty-five (25) foot wide trail easement are: Travel by foot, dogsled, animals, snowmobiles, two and three-wheel vehicles, and small all-terrain vehicles (less than 3,000 lbs. Gross Vehicle Weight (GVW)).

a. (EIN 3 C5) An easement for a proposed access trail twenty-five (25) feet in width from trail EIN 1 C1, C3, C6, D1 in Sec. 24, T. 14 S., R. 2 W., Kateel River Meridian, southerly to public lands. The uses allowed are those listed above for a twenty-five (25) foot wide trail easement. The season of use will be limited to winter use.

b. (EIN 5 C5) An easement for a proposed access trail twenty-five (25) feet in width from trail EIN 1 C1, C3, C6, D1 in Sec. 17, T. 14 S., R. 1 W., Kateel River Meridian, northwesterly to public lands. The uses allowed are those listed above for a twenty-five (25) foot wide trail easement. The season of use will be limited to winter use.

c. (EIN 8 C5) An easement for a proposed access trail twenty-five (25) feet in width from public lands in Sec. 31, T. 14 S., R. 3 E., Kateel River Meridian, southwesterly to public lands. The uses allowed are those listed above for a twenty-five (25) foot wide trail easement.

d. (EIN 8a C5) An easement for a proposed access trail twenty-five (25) feet in width from public lands in Sec. 36, T. 14 S., R. 1 E., Kateel River Meridian, southeasterly to public lands. The uses allowed are those listed above for a twenty-five (25) foot wide trail easement.

e. (EIN 10a C5) An easement for a proposed access trail twenty-five (25) feet in width from public lands in Sec. 1, T. 14 S., R. 1 E., Kateel River Meridian, northeasterly to public lands. The uses allowed are those listed above for a twenty-five (25) foot wide trail easement.

f. (EIN 15 C5) An easement for a proposed access trail twenty-five (25) feet in width from Sec. 1, T. 13 S., R. 2 W., Kateel River Meridian, northeasterly to Sec. 31, T. 12 S., R. 1 W., Kateel River Meridian. The uses allowed are those listed above for a twenty-five (25) foot wide trail easement.

g. (EIN 15c C5) An easement for a proposed access trail twenty-five (25) feet in width from public lands in Sec. 1, T. 12 S., R. 1 E., Kateel River Meridian, northeasterly to public lands. The uses allowed are those listed above for a twenty-five (25) foot wide trail easement.

h. (EIN 15d C5) An easement for a proposed access trail twenty-five (25) feet in width from public lands in Sec. 6, T. 11 S., R. 2 E., Kateel River Meridian, northwesterly to public lands. The uses allowed are those listed above for a twenty-five (25) foot wide trail easement.

i. (EIN 16a C5) An easement for a proposed access trail twenty-five (25) feet in width from public lands in Sec. 1, T. 13 S., R. 2 E., Kateel River Meridian, northeasterly to public lands. The uses allowed are those listed above for a twenty-five (25) foot wide trail easement.

The grant of the above-described lands shall be subject to:

1. Issuance of a patent confirming the boundary description of the unsurveyed lands hereinabove granted after approval and filing by the Bureau of Land Management of the official plat of survey covering such lands; and

2. Valid existing rights therein, if any, including but not limited to those created by any lease (including a lease issued under Sec. 6(g) of the Alaska Statehood Act of July 7, 1958 (72 Stat. 339, 341; 48 U.S.C. Ch. 2, Sec. 6(g) (1976))), contract, permit, right-of-way, or easement, and the right of the lessee, contractee, permitee, or grantee to the complete enjoyment of all rights, privileges, and benefits thereby granted to him. Further, pursuant to Sec. 17(b)(2) of the Alaska Native Claims Settlement Act, any valid existing right recognized by the Alaska Native Claims Settlement Act shall continue to have whatever right of access as is now provided for under existing law.

To date approximately 1,277,463 acres of land, selected pursuant to Sec. 12(c) of the Alaskan Native Claims Settlement Act, have been approved for conveyance to Doyon, Limited.

Within the above described lands, only the following inland water body is considered to be navigable:

Khotol River.

In accordance with Departmental regulation 43 CFR 2650.7(d), notice of this decision is being published once in the Federal Register and once a week, for four (4) consecutive weeks, in the Fairbanks Daily News-Miner. Any party claiming a property interest in lands affected by this decision may appeal the decision to the Alaska Native Claims Appeal Board, P.O. Box 2433, Anchorage, Alaska 99510 with a copy served upon both the Bureau of Land management, Alaska State Office, 701 C Street, Box 13, Anchorage, Alaska 99513 and the Regional Solicitor, Office of the Solicitor, 510 L Street, Suite 408, Anchorage 99501, also:

1. Any party receiving service of this decision shall have 30 days from the receipt of this decision to file an appeal.

2. Any unknown parties, any parties unable to be located after reasonable efforts have been expended to locate, and any parties who failed or refused to sign the return receipt shall have until November 5, 1979, to file an appeal.

3. Any party known or unknown who may claim a property interest which is adversely affected by this decision shall be deemed to have waived those rights which were adversely affected unless an appeal is timely filed with the Alaska Native Claim Appeal Board.

To avoid summary dismissal of the appeal, there must be strict compliance with the regulations governing such appeals. Further information on the manner of and requirements for filing an appeal may be obtained from the Bureau of Land Management, 701 C Street, Box 13, Anchorage, Alaska 99513.

If an appeal is taken, the party to be served with a copy of the notice of appeal is:

Doyon, Limited, First and Hall Streets, Fairbanks, Alaska 99701.

Ramona M. Chinn,
Acting Chief, Branch of Adjudication.

[FR Doc. 79-30929 Filed 10-4-79; 8:45 am]
BILLING CODE 4310-84-M

[AA-6979-A and AA-6979-B]

Alaska Native Claims Selection

On May 16, 1974, Shaan-Seet Incorporated for the Native village of Craig, filed selection application AA-6979-A, and on December 12, 1974, filed selection application AA-6979-B under the provisions of Sec. 16(b) of the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 706; 43 U.S.C. 1601, 1615(b) (1976)) (ANCSA), for the surface estate of certain lands in the vicinity of Craig.

As to the lands described below, the applications, as amended, are properly filed and meet the requirements of the Alaska Native Claims Settlement Act and of the regulations issued pursuant thereto. These lands do not include any lawful entry perfected under or being maintained in compliance with laws leading to acquisition of title.

In view of the foregoing, the surface estate of the following described lands, selected pursuant to Sec. 16(b) of ANCSA, aggregating approximately 20,857 acres, is considered proper for acquisition by Shaan-Seet Incorporated and is hereby approved for conveyance pursuant to Sec. 14(b) of ANCSA.

U.S. Survey 1429, Track E, situated on an island in Klawak Inlet, off West shore of Prince of Wales Island, Craig, Alaska.
Containing 0.74 acre.
U.S. Survey 2613, situated on the N.W. side Craig-Klawak Highway about ¾ mile N.E. of Craig, Alaska, on Crab Bay, Alaska.
Containing 4.72 acres.
Copper River Meridian, Alaska (Unsurveyed)
T. 73 S., R. 82 E.,
Sec. 19, W½NW¼, SW¼;
Sec. 28, SW¼SW¼;
Sec. 29, SW¼NW¼, SW¼, NW¼SE¼, S½SE¼;
Secs. 30, 31 and 32, all;
Sec. 33, W½NW¼, SW¼, NW¼SE¼, S½SE¼;
Sec. 34, S½SW¼.
Containing approximately 2,878 acres.
T. 74 S., R. 80 E.,
Sec. 1 (fractional), excluding Native allotment application AA-7833 Parcel B.
Containing approximately 70 acres.
T. 74 S., R. 81 E.
Secs. 1 to 4, inclusive, all;
Sec. 5 (fractional), excluding U.S. Surveys 1429, 1429-A, 2327, 2611, 2612, 2613 and 3857 and AA-26435, Alaska Native Claims Settlement Act, Sec. 3(e) application for a U.S. Coast Guard Shelter Cove Light and AA-27184, Alaska Native Claims Settlement Act, Sec. 3(e) application for a U.S. Forest Service Administrative Site;
Sec. 6 (fractional), excluding U.S. Surveys 1429 and 1429-A and Native allotment application AA-7883 Parcel B;
Sec. 7 (fractional), excluding U.S. Surveys 1429 and 1429-A;
Sec. 8 (fractional), excluding U.S. Surveys 1429, 1429-A, 2611 and 3857 and AA-26435, Alaska Native Claims Settlement Act, Sec. 3(e) application for a U.S. Coast Guard Shelter Cove Light and AA-27184, Alaska Native Claims Settlement Act, Sec. 3(e) application for a U.S. Forest Service Administrative Site;
Secs. 9 to 12, inclusive, all;
Secs. 13 to 17 (fractional), all;
Secs. 21 to 28 (fractional), all;
Secs. 32 to 36 (fractional), all.
Containing approximately 10,080 acres.
T. 74 S., R. 82 E.,
Sec. 3, S½NE¼, W½, SE¼;
Secs. 4 to 8, inclusive, all;
Sec. 17, (fractional), N½, SW¼, N½SE¼;
Sec. 18 (fractional), all;
Sec. 19, N½NW¼.
Containing approximately 4,722 acres.
T. 75 S., R. 81 E.,
Sec. 1 (fractional), W½, NW¼SE¼, S½SE¼;
Sec. 2 (fractional), NE¼;
Sec. 4 (fractional), NW¼NW¼;
Secs. 5 and 6 (fractional), all;
Sec. 7 (fractional), E½;
Sec. 8 (fractional), S½;
Sec. 9 (fractional), S½;
Sec. 12 (fractional), NE¼;
Sec. 14 (fractional), all;
Sec. 15 (fractional), N½, E½SW¼, N½SE¼, SW¼SE¼;
Sec. 16 (fractional), N½, N½SW¼, NW¼SE¼;
Sec. 22, W½NE¼;
Sec. 23 (fractional), E½, E½NW¼, NW¼NW¼;
Sec. 24 (fractional), SW¼, W½SE¼;
Sec. 25 (fractional), NW¼, N½SW¼, SE¼SW¼, W½SE¼.
Containing approximately 3,102 acres.
Aggregating approximately 20,857 acres.

The conveyance issued for the surface estate of the lands described above shall contain the following reservations to the United States:

1. The subsurface estate therein, and all rights, privileges, immunities, and appurtenances, of whatsoever nature, accruing unto said estate pursuant to the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 704; 43 U.S.C. 1601, 1613(f) (1976)); and

2. Pursuant to Sec. 17(b) of the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 708; 43 U.S.C. 1601, 1616(b) (1976)), the following public easements, referenced by easement identification number (EIN) on the easement map attached to this document, copy of which will be found in casefile AA-6979-EE, are reserved to the United States. All easements are subject to applicable Federal, State, or municipal corporation regulation. The following is a listing of uses allowed for each type of easement. Any uses which are not specifically listed are prohibited.

25 Foot Trail—The uses allowed on a twenty-five (25) foot wide trail easement are: travel by foot, dogsleds, animals, snowmobiles, two and three-wheel vehicles, and small all-terrain vehicles (less than 3,000 lbs. Gross Vehicle Weight (GVW)).

One Acre Site—The uses allowed for a site easement are: vehicle parking (e.g., aircraft, boats, ATV's, snowmobiles, cars, trucks), temporary camping, and loading or unloading. Temporary camping, loading or unloading shall be limited to 24 hours.

a. (EIN la E, G) A one (1) acre site easement upland of the mean high tide line in Sec. 36, T. 74 S., R. 81 E., Copper River Meridian, on the west shore of an unnamed bay east of Culebrina Island. The uses allowed are those listed above for a one (1) acre site easement.

b. (EIN lc C5, E) An easement for a proposed access trail twenty-five (25) feet in width from site EIN la E, G, in Sec. 36, T. 74 S., R. 81 E., Copper River Meridian, easterly to public lands. The uses allowed are those listed above for a twenty-five (25) foot wide trail easement.

c. (EIN 16 L) A one-quarter (¼) acre site easement for an existing water intake facility located in Secs. 8 and 9, T. 74 S., R. 81 E., Copper River Meridian. The uses allowed are those activities associated with the operation and maintenance of the water facility.

d. (EIN 17 L) An easement twenty (20) feet in width for an existing water pipeline beginning at a water intake facility (EIN 16 L) located in Secs. 8 and 9, T. 74 S., R. 81 E., Copper River Meridian, thence northwesterly to a water storage tank on the west shore of Port Bagial located in the northwest quarter of Sec. 8, T. 74 S., R. 81 E., Copper River Meridian. The uses allowed are those associated with the operation and maintenance of the water facility.

The grant of the above-described lands shall be subject to:

1. Issuance of a patent confirming the boundary description of the unsurveyed lands hereinabove granted after approval and filing by the Bureau of Land Management of the official plat of survey covering such lands;

2. Valid existing rights therein, if any, including but not limited to those created by any lease (including a lease issued under Sec. 6(g) of the Alaska Statehood Act of July 7, 1958 (72 Stat. 339, 341; 48 U.S.C. Ch. 2, Sec. 6(g) (1976))), contract, permit, right-of-way, or easement, and the right of the lessee, contractee, permittee, or grantee to the complete enjoyment of all rights, privileges, and benefits thereby granted to him. Further, pursuant to Sec. 17(b)(2) of the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 708; 43 U.S.C. 1601, 1616(b)(2) (1976) (ANCSA)), any valid existing right recognized by ANCSA shall continue to have whatever right of access as is now provided for under existing law.

3. A right-of-way, AA-8171, for a Federal Aid Secondary Highway, Act of August 27, 1958 (72 Stat. 885; 23 U.S.C. 317) in N½, Tract E of U.S. Survey 1429.

4. The following third-party interests, if valid, created and identified by the United States Forest Service, as provided by Sec. 14(g) of the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 704; 43 U.S.C. 1601, 1613 (1976)) as Special Use Permits issued to:

a. C.W.C. Fisheries, Inc., for maintaining a reservoir and water transmission line for cannery water supply for approximately 865 feet of water transmission line right-of-way eight feet wide extending from the East slope of Port Bagial to a dam on the West slope of Sunahee Mountain, and the reservoir approximately 20 feet by 60 feet by 3 feet average depth behind the five foot dam, covering 0.16 miles in Secs. 5, 6 and 8, T. 74 S., R. 81 E., Copper River Meridian.

b. Alaska Power and Telephone Company, for a primary fuel-generated power transmission line and a telephone line for a strip of land ten feet on either side of the transmission line, located parallel to the Craig-Klawock road, traversing approximately 5.68 miles in Sec. 5, T. 74 S., R. 81 E., Copper River Meridian.

c. City of Craig, for constructing, operating and maintaining a municipal water supply, including two wells, one well house approximately 20 feet by 20 feet, approximately 1,630 feet of eight inch cast iron water line and approximately 740 feet of three inch galvanized steel pipeline within and adjacent to the Craig-Klawock road right-of-way and traversing Sec. 5, T. 74 S., R. 81 E., Copper River Meridian.

d. City of Craig, to construct, operate, and maintain a municipal water supply intake and transmission line, including right-of-way 20 feet wide from spring at base of Sunnahee Mountain to Port Bagial, improvements allowed as follows: 1,289 feet of eight inch plastic pipe and one structure six feet by twenty feet by five feet for water intake in Secs. 8 and 9, T. 74 S., R. 81 E., Copper River Meridian.

e. R.C.A. Alaska Communication, Inc. for an electronic site for constructing, maintaining and renting a building to house electronic equipment, antenna support structure, driveway and parking area, and for installing, maintaining, renting and operating electronic transmission equipment on Sunny Hay Mountain in SW¼SE¼, Sec. 10, T. 74 S., R. 81 E., Copper River Meridian.

f. State of Alaska, Department of Highways, for a road right-of-way from the Craig Townsite elimination boundary to the Klawock Townsite elimination boundary, covering 5.604 miles and traversing Sec. 5, T. 74 S., R. 81 E., Copper River Meridian.

5. Requirements of Sec. 22(k) of the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 715; 43 U.S.C. 1601, 1621(k) (1976)), that, until December 18, 1983, the portion of the above-described lands located within the boundaries of a national forest shall be managed under the principles of sustained yield and under management practices for protection and enhancement of environmental quality no less stringent than such management practices on adjacent national forest lands; and

6. Requirements of Sec. 14(c) of the Alaska Native Claims Settlement Act of December 18, 1971 (85 Stat. 688, 703; 43 U.S.C. 1601, 1613(c) (1976)), that the grantee hereunder convey those portions, if any, of the lands hereinabove granted, as are prescribed in said section.

Shaan-Seet Incorporated is entitled to conveyance of 23,040 acres of land selected pursuant to Sec. 16(b) of ANCSA. Together with the lands herein approved, the total acreage conveyed or approved for conveyance is 20,857 acres. The remaining entitlement of approximately 2,183 acres will be conveyed at a later date.

Pursuant to Sec. 14(f) of ANCSA, conveyance to the subsurface estate of the lands described above shall be granted to Sealaska Corporation when conveyance is granted to Shaan-Seet Incorporated for the surface estate, and shall be subject to the same conditions as the surface conveyance.

There are no inland water bodies considered to be navigable within the above described lands.

In accordance with Departmental regulation 43 CFR 2650.7(d), notice of this decision is being published once in the Federal Register and once a week, for four (4) consecutive weeks, in the Ketchikan Daily News. Any party claiming a property interest in lands affected by this decision may appeal the decision to the Alaska Native Claims Appeal Board, P.O. Box 2433, Anchorage, Alaska 99510 with a copy served upon both the Bureau of Land Management, Alaska State Office, 701 C Street, Box 13, Anchorage, Alaska 99513 and the Regional Solicitor, Office of the Solicitor, 510 L Street, Suite 408, Anchorage, Alaska 99501, also:

1. Any party receiving service of this decision shall have 30 days from the receipt of this decision to file an appeal.

2. Any unknown parties, any parties unable to be located after reasonable efforts have been expended to locate, and any parties who failed or refused to sign the return receipt shall have until November 5, 1979 to file an appeal.

3. Any party known or unknown who may claim a property interest which is adversely affected by this decision shall be deemed to have waived those rights which were adversely affected unless an appeal is timely filed with the Alaska Native Claims Appeal Board.

To avoid summary dismissal of the appeal, there must be strict compliance with the regulations governing such appeals. For further information on the manner of and requirements for filing an appeal may be obtained from the Bureau of Land Management, 701 C Street, Box 13, Anchorage, Alaska 99513.

If an appeal is taken, the parties to be served with a copy of the notice of appeal are:

Shaan-Seet Incorporated, P.O. Box 90, Craig, Alaska 99921.

Sealaska Corporation, One Sealaska Plaza, Suite 400, Juneau, Alaska 99801.

Ramona M. Chinn,

Acting Chief, Branch of Adjudication.

[FR Doc. 79-30930 Filed 10-4-79; 8:45 am]

BILLING CODE 4310-84-M

Outer Continental Shelf, North Atlantic Oil and Gas Lease Sale No. 42

1. *Authority.* This notice is published pursuant to the Outer Continental Shelf Lands Act (43 U.S.C. 1331-1343), as amended, and the regulations issued thereunder (43 CFR Part 3300).

(This notice supersedes Sale No. 42 published Friday September 28, 1979 (44 FR 56042))

2. *Filing of Bids.* Sealed bids will be received by the Manager, New York Outer Contintental Shelf (OCS) Office, Bureau of Land Management, at the Biltmore Plaza Hotel, Kennedy Plaza, Providence, Rhode Island 02903. Bids may be delivered in person to the Bureau at that address (State Suite B) from 1:00 p.m., to 5:00 p.m., e.s.t., November 5, 1979 or to that address (Grand Ballroom) from 8:30 a.m., e.s.t., to 9:30 a.m., e.s.t., November 6, 1979. Bids may also be delivered to the address in paragraph 14 until 4:45 p.m., e.s.t., Friday, November 2, 1979. Bids received by the Manager later than the times and dates specified above will be returned unopened to the bidders. Bids may not be modified or withdrawn unless written modification or withdrawal is received by the Manager prior to 9:30 a.m., e.s.t. November 6, 1979. All bids must be submitted and will be considered in accordance with applicable regulations, including 43 CFR Part 3300. The list of restricted joint bidders which applies to this sale was published in 44 FR 24348.

3. *Method of Bidding.* A separate bid in sealed envelope, labeled "Sealed Bid for Oil and Gas Lease (insert number of tract), not to be opened until 10 a.m., e.s.t. November 6, 1979", must be submitted for each tract.

A suggested form appears in 43 CFR Part 3300 (44 FR 38289) Appendix A. Bidders are advised that tract numbers are assigned solely for administrative purposes and are not the same as block numbers found on offical protraction diagrams. All bids received shall be deemed submitted for a numbered tract. Bidders must submit with each bid one-fifth of the cash bonus in cash or by cashier's check, bank draft, or certified check payable to the order of the Bureau of Land Management. No bid for less than a full tract as described in paragraph 13 will be considered. Bidders submitting joint bids must state on the bid form the proportionate interest of each participating bidder, in percent to a maximum of five decimal places, as well as submit a sworn statement that the bidder is qualified under 43 CFR Subpart 3316. The suggested form for this statement to be used in joint bids appears in 43 CFR Part 3300 (44 FR 38289) Appendix B. Other documents may be required of bidders under 43 CFR 3316.4. Bidders are warned against violation of 18 U.S.C. 1860, prohibiting unlawful combination or intimidation of bidders.

4. *Bonus Bidding With a Fixed Sliding Scale Royalty.* Bids on 42-18, 42-19, 42-20, 42-26, 42-27, 42-28, 42-78, 42-79, 42-80, 42-81, 42-89, 42-97, 42-98, 42-111, 42-112, 42-113, 42-117, 42-118, 42-119, 42-122, 42-123, 42-124, 42-125, 42-126, 42-127, 42-128, 42-130, 42-131, 42-132, 42-133, 42-134, 42-135, 42-136, 42-137, 42-138, 42-139, 42-140, 42-141, 42-142, 42-143, 42-144, 42-145, 42-146, 42-150, 42-151, 42-152, 42-153, 42-154, 42-155, 42-156, 42-157, 42-158, 42-162, 42-163, and 42-164 must be submitted on a cash bonus bid basis with the percent royalty due in amount or value of production saved, removed or sold fixed according to the sliding scale formula described below. This formula fixes the percent royalty at a level determined by the value of lease production during each calendar quarter. For purposes of determining percent royalty due on production during a quarter, the value of production during the quarter will be adjusted for inflation as described below. The determination of the value of the production on which royalty is due will be made pursuant to 30 CFR 250.64 and Sec. 6 (b) of the lease form.

The fixed sliding scale formula operates in the following way: when the quarter value of production, adjusted for inflation, is less than $15.929026 million, a royalty of 16.66667 percent in amount or value of production saved, removed or sold will be due on the unadjusted value or amount of production. When the adjusted quarterly value of production is equal to or greater than $15.929026 million, but less than or equal to $3423.822697 million, the royalty percent due on the unadjusted value or amount of production is given by

$$Rj = b\,(\mathrm{Ln}\,(Vj/S)).$$

Where:

Rj = the percent royalty that is due and payable on the unadjusted amount or value of all production saved, removed or sold in quarter j.
b = 9.0.
Ln = natural logarithm.
Vj = the value of production in quarter j, adjusted for inflation, in millions of dollars.
S = 2.5.

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Figure 1
Form of the Sliding Royalty Schedule

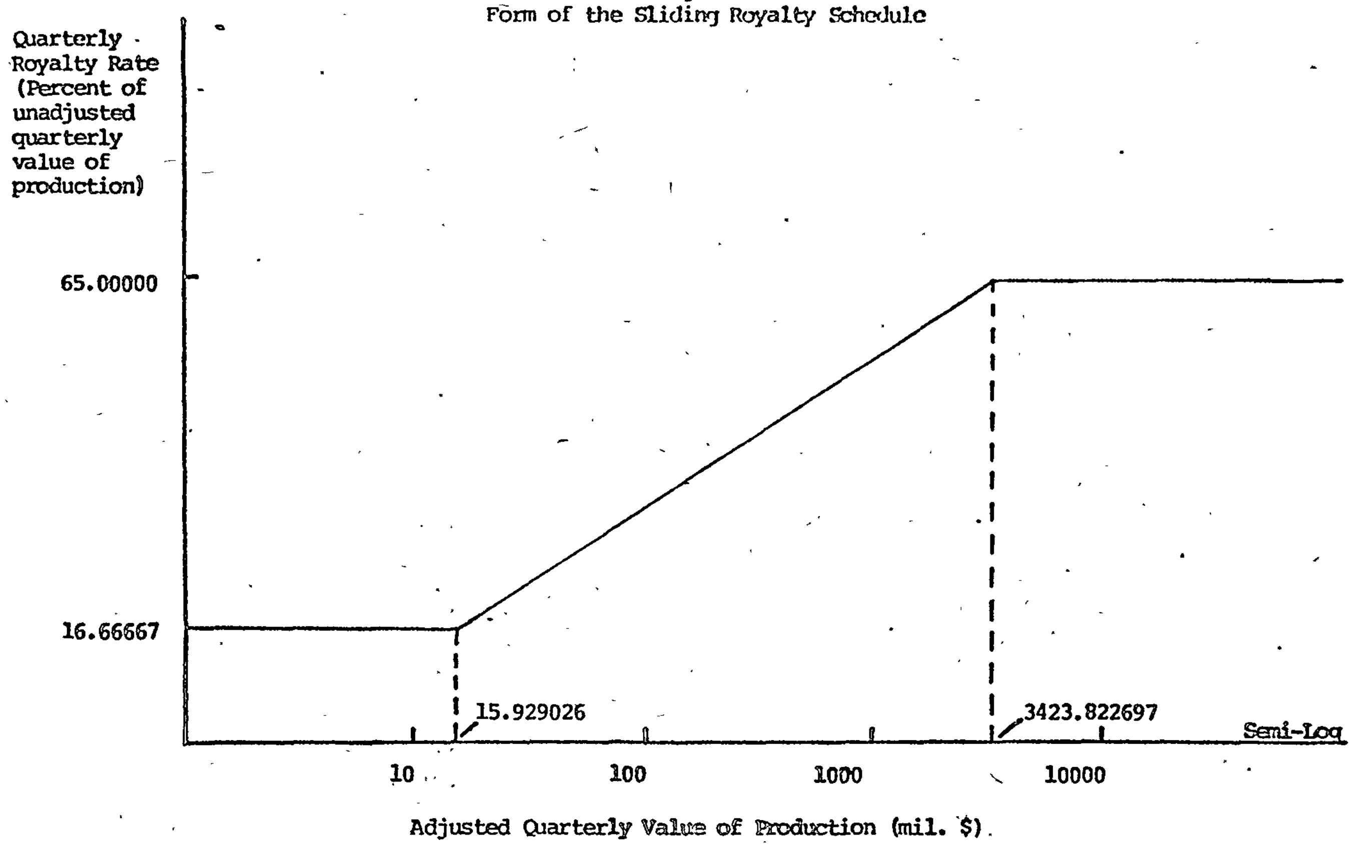

TABLE 1. HYPOTHETICAL QUARTERLY ROYALTY CALCULATIONS

(A) Actual Value of Quarterly Production (Millions of Dollars	(B) GNP Fixed Weighted Price Index	(C) Inflation Factor[1]	(D) Adjusted Value of Quarterly Production[2] (Vj, Millions of $)	(E) Percent Royalty Rate (Rj)	(F) Royalty Payment[3] (Millions of Dollars)
10.000000	200.0	4/3	7.500000	16.66667	1.666667
30.000000	200.0	4/3	22.500000	19.77502	5.932506
90.000000	200.0	4/3	67.500000	29.66253	26.696277
270.000000	200.0	4/3	202.500000	39.55004	106.785108
810.000000	200.0	4/3	607.500000	49.43755	400.444155
10.000000	250.0	4/3	6.000000	16.66667	1.666667
30.000000	250.0	4/3	18.000000	17.76673	5.330019
90.000000	250.0	4/3	54.000000	27.65424	24.888816
270.000000	250.0	4/3	162.000000	37.54175	101.362725
810.000000	250.0	4/3	486.000000	47.42926	384.177006

1 Column (B)) divided by 150.0 (assumed value of GNP fixed weighted price index at time leases are issued).

2 Column (A) divided by Inflation Factor.

3 Column (A) times Column (E) divided by 100.

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When the adjusted quarterly value of production is greater than $3423.822697 million, a royalty of 65.00000 percent in amount or value of production saved, removed, or sold will be due on the unadjusted quarterly value of production. Thus, in no instance will the quarterly royalty due exceed 65.00000 percent in amount or value of quarterly production saved, removed or sold.

In determining the quarterly percent royalty due, Rj, the calculation will be rounded to five decimal places (for example, 18.59859 percent). This calculation will incorporate the adjusted quarterly value of production, Vj in millions of dollars, rounded to the sixth digit, i.e., to the nearest dollar (for example, 19.743026 millions of dollars).

The form of sliding scale royalty schedule is illustrated in Figure 1. Note that the effective quarterly royalty rate depends upon the inflation adjusted quarterly value of production. However, this rate is applied to the unadjusted quarterly value of production to determine the royalty payments due.

In adjusting the quarterly value of production for use in calculating the percent royalty due on production during the quarter, the actual value of production will be adjusted to account for the effects of inflation by dividing the actual value of production by the following inflation adjustment factor. The inflation adjustment factor used will be the ratio of the GNP fixed weighted price index for the calendar quarter preceding the quarter of production to the value of that index for the quarter preceding the issuance of the lease. The GNP fixed weighted price index is published monthly in the Survey of Current Business by the Bureau of Economic Analysis, U.S. Department of Commerce. The percent royalty will be due and payable on the actual amount or value of production saved, removed, or sold as determined pursuant to 30 CFR 250.64 and Sec. 6(b) of the lease form. The timing of procedures for inflation adjustments and determinations of the royalty due will be specified at a later date. Table 1 provides hypothetical examples of quarterly royalty calculations using the sliding scale formula just described under two different values for the quarterly price index.

Leases awarded on the basis of cash bonus bid with fixed sliding scale royalty will provide for a yearly rental or minimum royalty payment of $8 per hectare or fraction thereof.

Bidders for these tracts should recognize that the Department of Energy is authorized, under Section 302 (b) and (c) of the Department of Energy Organization Act, to establish production rates for all Federal Oil and Gas leases.

5. *Bonus Bidding With a Fixed Constant Royalty.* Bids on the remaining tracts to be offered at this sale must be on a cash bonus basis with fixed royalty of 16⅔ percent. Leases which may be issued will provide for a yearly rental payment or minimum royalty payment of $8 per hectare or fraction thereof.

6. *Equal Opportunity.* Each bidder must have submitted by 9:30 a.m., e.s.t., November 6, 1979 the certification required by 41 CFR 60-1.7(b) and Executive Order No. 11246 of September 24, 1965, as amended by Executive Order No. 11375 of October 13, 1967, on the Compliance Report Certification Form, Form 1140-8 (November 1973), and the Affirmative Action Representation Form, Form 1140-7 (December 1971).

7. *Bid Opening.* Bids will be opened on November 6, 1979, beginning at 10 a.m., e.s.t., at the address stated in paragraph 2. The opening of the bids is for the sole purpose of publicly announcing and recording bids received and no bids will be accepted or rejected at that time. If the Department is prohibited for any reason from opening any bid before midnight, November 6, 1979, that bid will be returned unopened to the bidder, as soon thereafter as possible.

8. *Deposit of Payment.* Any cash, cashier's checks, certified checks, or bank draft, submitted with a bid may be deposited in a suspense account in the Treasury during the period the bids are being considered. Such a deposit does not constitute and shall not be construed as acceptance of any bid on behalf of the United States.

9. *Withdrawal of Tracts.* The United States reserves the right to withdraw any tract from this sale prior to issuance of a written acceptance of a bid for that tract.

10. *Acceptance or Rejection of Bids.* The United States reserves the right to reject any and all bids for any tract. In any case, no bid for any tract will be accepted and no lease for any tract will be awarded to any bidder unless:

(a) The bidder has complied with all requirements of this notice and applicable regulations;

(b) The bid is the highest valid cash bonus bid; and

(c) The amount of the bid has been determined to be adequate by the Secretary of the Interior.

No bid will be considered for acceptance unless it offers a cash bonus in the amount of $62 or more per hectare or fraction thereof.

11. *Successful Bidders.* Each person who has submitted a bid accepted by the Secretary of the Interior will be required to execute copies of the lease specified below, pay the balance of the cash bonus bid together with the first year's annual rental and satisfy the bonding requirements of 43 CFR 3318.1 within the time provided in 43 CFR 3316.5.

12. *Protraction Diagram.* Tracts offered for lease may be located on the following protraction diagrams which are available from the Manager, New York Outer Continental Shelf Office, Bureau of Land Management, 26 Federal Plaza, Suite 32-120, New York, New York 10007, at $2 each.

(a) Outer Continental Shelf Official Protraction Diagram No. NK 19-8, Chatham (Approved April 18, 1979).

(b) Outer Continental Shelf Official Protraction Diagram No. NK 19-9, (Approved March 20, 1975).

(c) Outer Continental Shelf Official Protraction Diagram No. NK 19-11 (Approved October 31, 1974).

(d) Outer Continental Shelf Official Protraction Diagram No. NK 19-12 (Approved April 29, 1975).

13. *Tract Descriptions.* The tracts offered for bid are as follows: Note: There may be gaps in the numbers of the tracts listed. Some of the blocks identified in the final environmental statement may not be included in this notice.

OCS Official Protraction Diagram NK 19-8, Chatham

[Approved April 18, 1979]

Tract	Block	Description	Hectares
42-3	643	All	2304
42-6	916	All	2304
42-7	917	All	2304
42-8	961	All	2304
42-9	962	All	2304
42-10	1006	All	2304

OCS Official Protraction Diagram NK 19-9

[Approved March 20, 1975]

Tract	Block	Description	Hectares
42-11	883	All	2304
42-12	884	All	2304
42-15	926	All	2304
42-16	927	All	2304
42-17	928	All	2304
42-18	930	All	2304
42-19	931	All	2304
42-20	932	All	2304
42-24	970	All	2304
42-25	971	All	2304
42-26	974	All	2304
42-27	975	All	2304
42-28	976	All	2304

OCS Official Protraction Diagram NK 19-11

[Approved October 31, 1974]

Tract	Block	Description	Hectares
42-38	38	All	2304
42-39	39	All	2304
42-40	80	All	2304
42-41	81	All	2304
42-42	82	All	2304
42-43	83	All	2304
42-44	84	All	2304
42-45	123	All	2304
42-46	124	All	2304
42-47	125	All	2304
42-48	128	All	2304
42-49	167	All	2304
42-50	168	All	2304
42-51	169	All	2304
42-52	171	All	2304
42-53	172	All	2304
42-54	214	All	2304
42-55	215	All	2304
42-56	216	All	2304
42-57	258	All	2304
42-58	259	All	2304
42-59	260	All	2304

OCS Official Protraction Diagram NK 19-12

[Approved April 29, 1975]

Tract	Block	Description	Hectares
42-76	1	All	2304
42-77	2	All	2304
42-78	6	All	2304
42-79	7	All	2304
42-80	8	All	2304
42-81	12	All	2304
42-88	45	All	2304
42-89	56	All	2304
42-90	57	All	2304
42-96	89	All	2304
42-97	99	All	2304
42-98	100	All	2304
42-99	101	All	2304
42-105	133	All	2304
42-106	134	All	2304
42-107	135	All	2304
42-108	136	All	2304
42-109	137	All	2304
42-110	138	All	2304
42-111	142	All	2304
42-112	143	All	2304
42-113	144	All	2304
42-114	145	All	2304
42-115	146	All	2304
42-116	177	All	2304
42-117	186	All	2304
42-118	187	All	2304
42-119	188	All	2304
42-120	189	All	2304
42-121	190	All	2304
42-122	226	All	2304
42-123	227	All	2304
42-124	228	All	2304
42-125	229	All	2304
42-126	230	All	2304
42-127	231	All	2304
42-128	232	All	2304
42-129	233	All	2304
42-130	266	All	2304
42-131	267	All	2304
42-132	269	All	2304
42-133	270	All	2304
42-134	271	All	2304
42-135	272	All	2304
42-136	273	All	2304
42-137	274	All	2304
42-138	310	All	2304
42-139	311	All	2304
42-140	312	All	2304
42-141	313	All	2304
42-142	314	All	2304
42-143	315	All	2304
42-144	316	All	2304
42-145	317	All	2304
42-146	318	All	2304
42-147	322	All	2304
42-148	323	All	2304
42-149	324	All	2304
42-150	353	All	2304
42-151	354	All	2304
42-152	355	All	2304
42-153	356	All	2304

OCS Official Protraction Diagram NK 19-12—Continued

[Approved April 29, 1975]

Tract	Block	Description	Hectares
42-154	357	All	2304
42-155	358	All	2304
42-156	359	All	2304
42-157	360	All	2304
42-158	361	All	2304
42-159	365	All	2304
42-160	366	All	2304
42-161	367	All	2304
42-162	397	All	2304
42-163	398	All	2304
42-164	399	All	2304
42-169	409	All	2304
42-170	410	All	2304

14. *Lease Terms and Stipulations.* All leases issued as a result of this sale will be for an initial term of 5 years. Leases issued as a result of this sale will be on Form 3300-1 (September 1978), available from the Manager, New York Outer Continental Shelf Office, Federal Building, Suite 32-120, 26 Federal Plaza, New York, New York 10007. Section 6 of the lease form will be amended for tracts offered on a cash bonus basis with a fixed sliding scale royalty, listed in paragraph 4 as follows:

Sec. 6 *Royalty on Production.* (a) To pay the lesser a royalty of that percent in amount or value of production saved, removed or sold from the leased area as determined by the sliding scale royalty formula as follows. When the quarterly value of production, adjusted for inflation, is less than $15.929026 million, a royalty of 16.66667 percent in amount or value of production saved, removed or sold will be due on the unadjusted value or amount of production. When the adjusted quarterly value of production is equal to or greater than $15.929026 million, but less than or equal to $3423.822697 million, the royalty percent due on the unadjusted value or amount of production is given by

$Rj = b(Ln(Vj/S))$.

Where:

Rj = the percent royalty that is due and payable on the unadjusted amount or value of all production saved, removed or sold in quarter j.

$b = 9.0$.

Ln = natural logarithm.

Vj = the value of production in quarter j, adjusted for inflation, in millions of dollars.

$S = 2.5$.

When the adjusted quarterly value of production is greater than $3423.822697 million, a royalty of 65.00000 percent in amount or value of production saved, removed or sold will be due on the unadjusted quarterly value of production. Thus, in no instance will the quarterly royalty due exceed 65.00000 percent in amount or value of quarterly production saved, removed or sold.

In determining the quarterly percent royalty due, Rj, the calculation will be rounded to five decimal places (for example, 18.59859 percent). This calculation will incorporate the adjusted quarterly value of production, Vj, in millions of dollars, rounded to the sixth digit, i.e., to the nearest dollar (for example, 19.743028 millions of dollars). Gas of all kinds (except Helium) is subject to royalty. The lessor shall determine whether production royalty shall be paid in amount or value.

Except as otherwise noted, the following stipulations will be included in each lease resulting from this sale. In the following stipulations the term Supervisor refers to the Atlantic Area Oil and Gas Supervisor for Operations of the Geological Survey and the term Manager refers to the Manager of the New York OCS Office of the Bureau of Land Management.

Stipulation No. 1

If the Supervisor having reason to believe that a site, structure or object of historical or archeological significance hereinafter referred to as "cultural resource", may exist in the lease area, gives the lessee written notice that the lessor is invoking the provisions of this stipulation, the lessee shall upon receipt of such notice comply with the following requirements:

Prior to any drilling activity or the construction or placement of any structure for exploration or development on the lease, including but not limited to, well drilling and pipeline and platform placement, hereinafter in this stipulation referred to as "operation," the lessee shall conduct remote sensing surveys to determine the potential existence of any cultural resource that may be affected by such operations. All data produced by such remote sensing surveys as well as other pertinent natural and cultural environmental data shall be examined by a qualified marine survey archeologist to determine if indications are present suggesting the existence of a cultural resource that may be adversely affected by any lease operation. A report of this survey and assessment prepared by the marine survey archeologist shall be submitted by the lessee to the Supervisor and to the Manager for review.

If such cultural resource indicators are present the lessee shall: (1) locate the site of such operation so as not to adversely affect the identified location; or (2) establish, to the satisfaction of the Supervisor, on the basis of further archeological investigation conducted by a qualified marine survey archeologist or underwater archeologist using such survey equipment and technique as deemed necessary by the Supervisor, either that such operation will not adversely affect the location identified or that the potential cultural resource suggested by the occurrence of the indicators does not exist.

A report of this investigation prepared by the marine survey archeologist shall be submitted to the Supervisor and the Manager for their review. Should the Supervisor determine that the existence of a cultural resource which may be adversely affected by such operation is sufficiently established to warrant protection, the lessee shall take no action that may result in an adverse effect on such cultural resource until the Supervisor has given directions as to its preservation.

The lessee agrees that if any site, structure, or object of historical or archeological significance should be discovered during the conduct of any operations on the leased area, he shall report immediately such findings to the Supervisor, and make every reasonable effort to preserve and protect the cultural resource from damage until the Supervisor has given directions as to its preservation.

Stipulation No. 2

If biological populations or habitats which may require additional protection are identified by the Supervisor in the leasing area, the Supervisor will require the lessee to conduct environmental surveys or studies, including sampling as, approved by the Supervisor, to characterize existing environmental conditions in an identified zone prior to oil and gas operations, and to determine the extent and composition of biological populations or habitats, and the effects of proposed or existing operations on the populations or habitats which might require additional protective measures. The Supervisor shall provide written notice to the lessee of his decision to require such surveys or studies. The nature and extent of any surveys or studies will be determined by the Supervisor on a case-by-case basis.

Based on any surveys or studies which the Supervisor may require of the lessee, the Supervisor may require the lessee to: (1) relocate the site of operations so as not to affect adversely the significant biological populations or habitats deserving protection; (2) modify operations in such a way as not to affect adversely the significant biological populations or habitats deserving protection; or (3) establish to the satisfaction of the Supervisor that such operations will not adversely affect the significant biological populations or habitats deserving protection. Based on any surveys or studies which the Supervisor may require of the lessee, the Supervisor may also require the lessee to provide for periodic sampling of environmental conditions during operations.

The lessee shall submit all data obtained in the course of such surveys or studies to the Supervisor, with the locational information for drilling or other activity. The lessee may take no action that might result in any effect on the biological populations or habitats surveyed, until the Supervisor provides written directions to the lessee, with regard to permissible actions.

In the event that important biological populations or habitats are identified subsequent to commencement of operations, the lessee shall make every reasonable effort to preserve and protect all biological populations and habitats within the lease area, until the Supervisor provides written instructions to the lessee with regard to the biological populations or habitats identified.

Stipulation No. 3

Pipelines will be required, (1) if pipeline rights-of-way can be determined and obtained, (2) if laying such pipelines is technically feasible and environmentally preferable, and (3) if, in the opinion of the lessor, pipelines can be laid without net social loss, taking into account any incremental costs of pipelines over alternative methods of transportation and any incremental benefits in the form of increased environmental protection or reduced multiple use conflicts. The lessor specifically reserves the right to require that any pipeline used for transporting production to shore be placed in certain designated management areas. In selecting the means of transportation, consideration will be given to any recommendation of the intergovernmental planning program for assessment and management of transportation of Outer Continental Shelf oil and gas with the participation of Federal, State, and local government and industry. Where feasible and environmentally preferable, all pipelines, including both flow lines and gathering lines for oil and gas, shall be buried to a depth suitable for adequate protection from water currents, sand waves, storm scouring, fisheries' trawling gear, and other factors as determined on a case-by-case basis. All valves, taps, or other irregular surfaces that might be vulnerable or might damage fishing gear will be buried to a minimum of one foot or to a depth suitable for adequate protection or covered with an approved protective dome which will allow commercial trawl gear to pass over the structure without snagging or damaging the structure or fishing gear.

Following the completion of pipeline installation, no crude oil production will be transported by surface vessel from offshore production sites, except in the case of emergency. Determinations as to emergency conditions and appropriate responses to these conditions will be made by the Supervisor. Where the three criteria set forth in the first sentence of this stipulation are not met and surface transportation must be employed, all vessels used for carrying hydrocarbons to shore from the leased area will conform with all standards established for such vessels pursuant to the Ports and Waterways Safety Act of 1972 as amended (46 U.S.C. 391a).

Stipulation No. 4

The Supervisor may require the lessee to dispose of drill cuttings and drilling muds by shunting the material to a depth and location below the ocean surface as specified by the Supervisor, or by transporting the material to disposal sites approved by the Environmental Protection Agency. The Supervisor shall determine the method of disposal based upon review of the data obtained from the surveys and studies established pursuant to stipulation No. 2, and from other relevant sources of information.

Based upon the composition of produced formation waters, the site-specific environmental conditions in a leasing area, and the data obtained from the surveys and studies established pursuant to stipulation No. 2, as well as data from other relevant sources, the Supervisor may require the lessee to reinject formation waters. The Supervisor shall provide written notice to the lessee of a decision to require reinjection of such formation waters.

Stipulation No. 5

(The lease for the following tract will include this stipulation, which will apply only to operations within the designated portion of this tract: 42–43, NW¼, N½ SW¼)

Portions of this tract may contain a shallow "bright spot" seismic amplitude anomaly which may be indicative of a shallow gas deposit. Surface occupancy above this anomaly and drilling through the anomaly will not be allowed unless or until the lessee has demonstrated to the Supervisor's satisfaction that a potentially hazardous accumulation of shallow gas does not exist or that exploratory drilling operations, structures (platforms), casing, and wellheads can be placed, or drilling plans designed to assure safe operations in the area above the anomaly. This may necessitate all exploration for and development of oil and gas be performed from locations outside the area of concern, either within or outside this lease block.

Stipulation No. 6

The lessee shall include in his exploration and development plans submitted under 30 CFR 250.34 a proposed fisheries training program for review and approval by the Supervisor pursuant to this stipulation. The training program shall be for the personnel involved in vessel operations (related to offshore exploration and development and production operations); and platform and shorebased supervisors. The purpose of the training program shall be to familiarize persons working on the project of the value of the commercial fishing industry and the methods of offshore fishing operations and the potential hazards, conflicts and impacts resulting from offshore oil and gas activities. The program shall be formulated and implemented by qualified and experienced instructors in the kinds of fishing activities, methods of communication and navigational safety.

Stipulation No. 7

(To be included in any leases resulting from this sale for the sliding scale royalty tracts listed in paragraph 4 of this notice)

(a) The royalty rate on production saved, removed or sold from this lease is subject to consideration for reduction under the same authority that applies to all other oil and gas leases on the Outer Continental Shelf (30 CFR 250.12(e)). The Director, Geological Survey, may grant a reduction for only one year at a time. Reduction of royalty rates will not be approved unless production has been underway for one year or more.

(b) Although the royalty rate specified in Sec. 6(a) of this lease or as subsequently modified in accordance with applicable regulations and stipulations is applicable to all production under this lease, not more than 16⅔ percent of the production saved, removed or sold from the lease area may be taken as royalty on amount, except as provided in Sec. 15(d) of this lease; the royalty on any portion of the production saved, removed or sold from the lease in excess of 16⅔ percent may only be taken in value of the production saved, removed or sold from the lease area.

Stipulation No. 8

(To be included only in the lease resulting from this sale for tract 42-3)

(a) The lessee agrees that prior to operating or causing to be operated on its behalf boat or aircraft traffic into individual, designated warning areas, the lessee shall coordinate and comply with instructions from the Commander, Submarine Squadron Two, Naval Submarine Base, New London, Connecticut. Such coordination and instruction will provide for positive control of boats and aircraft operating into the warning areas at all times.

(b) Whether or not compensation for such damage or injury might be due under a theory of strict or absolute liability or otherwise, the lessee assumes all risks of damage or injury to persons or property, which occurs in, on, or above the Outer Continental Shelf, to any person or persons or to any property of any person or persons who are agents, employees or invitees of the lessee, its agents, independent contractors or subcontractors doing business with the lessee in connection with any activities being performed by the lessee in, on, or above the Outer Continental Shelf, if such injury or damage to such person or property occurs by reason of the activities of any agency of the U.S. Government, its contractors, or subcontractors, or any of their officers, agents or employees, being conducted as a part of, or in connection with, the programs and activities of Commander, Submarine Squadron Two, Naval Submarine Base, New London, Connecticut or other appropriate military agency.

Notwithstanding any limitations of the lessee's liability in Section 14 of the lease, the lessee assumes the risk whether such injury or damage is caused in whole or in part by any act or omission, regardless of negligence or fault, of the United States, its contractors or subcontractors, or any of their officers, agents, or employees. The lessee further agrees to indemnify and save harmless the United States against all claims for loss, damage, or injury sustained by the lessee, and to indemnify and save harmless the United States against all claims for loss, damage, or injury sustained by the agents, employees, or invitees of the lessee, its agents or any independent contractors or subcontractors doing business with the lessee in connection with the programs and activities of the aforementioned military installations and agencies whether the same be caused in whole or in part by the negligence or fault of the United States, its contractors, or subcontractors, or any of their officers, agents, or employees and whether such claims might be sustained under theories of strict or absolute liability or otherwise.

(c) The lessee agrees to control his own electromagnetic emissions and those of his agents, employees, invitees, independent contractors or subcontractors emanating from individual, designated defense warning areas in accordance with requirements specified by the Commander, Submarine Squadron Two, Naval Submarine Base, New London, Connecticut, to the degree necessary to prevent damage to, or unacceptable interference with Department of Defense flight, testing or operational activities conducted within individual designated warning areas. Necessary monitoring control and coordination with the lessee, his agents, employees, invitees, independent contractors or subcontractors, will be affected by the commander of the appropriate onshore military installation conducting operations in the particular warning area: Provided however, that control of such electromagnetic emissions shall permit at least one continuous channel of communication between a lessee, its agents, employees, invitees, independent contractors or subcontractors and onshore facilities.

15. *Information to Lessees.* On September 18, 1978, Congress passed amendments to the OCS Lands Act of 1953. Some sections of current regulations applicable to OCS leasing operations are inconsistent with this new legislation, and the legislation requires the issuance of some new regulations. The inconsistencies will be corrected by rulemakings and the new regulations will be issued as soon as possible. Nevertheless, bidders are notified that provisions of the new OCS Lands Act Amendments shall apply to all leases offered at this lease sale and shall supersede all inconsistent provisions in current regulations applicable to OCS leasing operations.

Some of the tracts offered for lease may fall in areas which may be included in fairways, precautionary zones, or traffic separation schemes. Corps of Engineers permits are required for construction of any artificial islands, installations and other devices permanently or temporarily attached to the seabed located on the Outer Continental Shelf Lands in accordance with section 4(e) of the Outer Continental Shelf Lands Act, as amended.

Bidders are advised that the Departments of the Interior and Transportation have entered into a Memorandum of Understanding dated May 6, 1976, concerning the design, installation, operation and maintenance of offshore pipelines. Bidders should consult both Departments for regulations applicable to offshore pipelines.

Bidders are also advised that in accordance with Sec. 16 of each lease offered at this sale the lessor may require a lessee to operate under a unit, pooling or drilling agreement and that the lessor will give particular consideration to requiring unitization in instances where one or more reservoirs underlie two or more leases with either a different royalty rate or a royalty rate based on a sliding scale.

A Biological Task Force (BTF) has been established to advise the Supervisor on those aspects of oil and gas operations resulting from lease Sale #42 that affect biological resources on Georges Bank and their habitats. The BTF is composed of designated representatives of the Bureau of Land Management, U.S. Fish and Wildlife Service, U.S. Geological Survey, NOAA, and the Environmental Protection Agency. Representatives of the affected coastal States may participate in activities of the BTF, but will not be formal members. It is intended that this BTF will remain in existence throughout the operating life of the field. The Supervisor will consult with the BTF in identifying areas or resources of biological importance, on the conduct of the biological surveys or studies, including periodic sampling of environmental conditions by lessees, and on the appropriate course of action after they surveys have been conducted.

In applying safety, environmental, and conservation laws and regulations the Supervisor, in accordance with Sec. 21(b) of the OCS Lands Act, as amended, will require the use of the best available and safest technologies which the Secretary determines to be economically feasible, wherever failure of equipment would have a significant effect on safety, health, or the environment, except where the Secretary determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies. To the extent practical, the Supervisor will consult with the relevant Federal agencies and the affected State(s) in the execution of these responsibilities.

Bidders are advised that the Secretary of the interior has directed that a development phase Environmental Impact Statement (EIS) be prepared for the North Atlantic lease sale area. The content of this EIS will be in accordance with the rules and regulations promulgated by the Department.

If significant biological populations or habitats are identified by the lessee subsequent to commencement of operations, the Supervisor will provide written instructions to the lessee within 15 working days with regard to the biological populations or habitats identified.

Each lessee shall, soon after the award of the lease, submit to the Supervisor the name(s) of individual(s) who will be responsible for preparing an exploration plan. The Supervisor shall provide these names to the affected States.

It will be required that in the immediate vicinity of drilling operations an open sea skimming unit equivalent to Clean Atlantic Associate Fast Response Unit Model II and 1000 feet of open sea oil containment boom be maintained. In addition, a suitable deployment vessel and personnel trained in deployment and use of this equipment should be immediately available. As part of the approval of development and production plans, suitable pollution prevention equipment will be required in the immediate vicinity of development and production operations.

Bidders are advised that the Intergovernmental Planning Program for OCS Oil and Gas Leasing, Transportation and Related Facilities (IPP) is being implemented nationwide. The post-sale procedures of the IPP will be applicable to lease sale 42. The North Atlantic Regional Technical Working Group Committee of the OCS Advisory Board has been established as the organizational component of the IPP for the North Atlantic.

16. *OCS Orders.* Operations on all leases resulting from this sale will be conducted in accordance with the provisions of all Outer Continental Shelf Atlantic Orders, as of their effective date, and any other applicable OCS Order as it becomes effective.

Ed Hastey,

Associate Director, Bureau of Land Management.

Dated: October 2, 1979.

Approved:

Cecil D. Adams,

Secretary of the Interior.

[FR Doc. 79-30838 Filed 10-4-79; 8:45 am]

BILLING CODE 4310-84-M

Fish and Wildlife Service

Endangered and Threatened Species Permit; Receipt of Application

Applicant: Department of Vertebrate Zoology, Natural History Museum, Smithsonian Institution, Washington, D.C.

The applicant requests a permit to import bone and keratin from hawksbill (*Eretmochelys imbricata*), green (*Chelonia mydas*) and loggerhead (*Caretta caretta*) sea turtles to develop aging techniques. Only salvaged material will be used. No additional specimens will be killed for this research.

Documents and other information submitted with this application are available to the public during normal business hours in Room 601, 1000 N. Glebe Road, Arlington, Virginia, or by writing to the Director, U.S. Fish and Wildlife Service (WPO), Washington, D.C. 20240.

This application has been assigned file number PRT 2-4749. Interested persons may comment on this application within 30 days of the date of this publication by submitting written data, views, or arguments to the Director at the above address. Please refer to the file number when submitting comments.

Dated: September 27, 1979.

Donald G. Donahoo,

Chief, Permit Branch, Federal Wildlife Permit Office, Fish and Wildlife Service.

[FR Doc. 79-30840 Filed 10-4-79; 8:45 am]

BILLING CODE 4310-55-M

Threatened Species Permit

A "Threatened Species Permit—Receipt of Permit Renewal Requests" was published in the Federal Register Vol. 44, No. 171, Friday, August 31, 1979 and listed as an applicant the Henry Vilas Zoo, 702 S. Randall Ave., Duluth, Minnesota 55803. The city and state in this address is incorrect and should be amended to read Madison, Wisconsin 53715.

Dated: September 24, 1979.

Donald G. Donahoo,

Chief, Permit Branch, Federal Wildlife Permit Office, Fish and Wildlife Service.

[FR Doc. 79-30839 Filed 10-4-79; 8:45 am]

BILLING CODE 4310-55-M

Availability of Environmental Assessments for Wildlife Restoration Projects

AGENCY: Fish and Wildlife Service, Department of the Interior.

ACTION: Notice of Availability for Inspection and Public Comment.

SUMMARY: This notice provides a listing of Environmental Assessments available for public review to supplement those previously listed in the Federal Register July 20, August 3, and September 6, 1979. The Assessments and Findings of No Significant Impact were prepared on certain projects conducted by State fish and wildlife agencies under the Federal Aid in Wildlife Restoration program. The public is invited to comment, and information is provided on the locations

at which the documents may be reviewed.

DATE: Comments must be received at the locations indicated by November 5, 1979.

ADDRESSES: The assessments are available for inspection at the following locations:

FWS Federal Aid Office, 1000 N. Glebe Road, Arlington, Virginia 22201
Region 1, FWS, Lloyd 500 Building, Suite 1692, 500 N.E. Multnomah Street, Portland, Oregon 97232
Region 2, FWS, 500 Gold Avenue, S.W., P.O. Box 1306, Albuquerque, New Mexico 87103
Region 3, FWS, Federal Building, Fort Snelling, Twin Cities, Minnesota 55111
Region 4, FWS, Richard B. Russell Federal Building, 75 Spring Street, SW., Atlanta, Georgia 30303
Region 5, FWS, 1 Gateway Center, Suite 700, Newton Corners, Massachusetts 02158
Region 6, FWS, P.O. Box 25486, Denver Federal Center, Denver, Colorado 80225
Alaska Area Office, FWS, 1011 E. Tudor Road, Anchorage, Alaska 99507
Central headquarters office of the State fish and wildlife agency

Interested persons are invited to submit comments to the appropriate Regional Director at the above regional addresses within 30 days. Copies of the assessment may be obtained at the Regional Offices upon payment of reasonable reproduction costs pursuant to 43 CFR, Part 2, Appendix A. Copies of any Finding of No Significant Impact will be provided free of cost.

FOR FURTHER INFORMATION CONTACT: Mr. Charles K. Phenicie, Chief, Division of Federal Aid, U.S. Fish and Wildlife Service, Washington, D.C. 20240, telephone 703-235-1526.

SUPPLEMENTARY INFORMATION: On June 26, 1979, the U.S. District Court for the District of Columbia issued an order dismissing Civil Action No. 78-430 involving the Federal Aid in Wildlife Restoration program. The dismissal effected an agreement by plaintiffs and defendants which included a provision that the Fish and Wildlife Service would publish in the Federal Register a notice of availability of certain Environmental Assessments for inspection and public comment. Pursuant to the stipulated agreement, this notice lists Environmental Assessments prepared to date and will be supplemented as other assessments are prepared.

The principal author of this notice is Dr. Robert J. Sousa, U.S. Fish and Wildlife Service, Division of Federal Aid, Washington, D.C. 20240, telephone 703-235-1526.

Notice is hereby given of availability for inspection and comment of environmental assessments for the following Federal Aid projects funded in part by the U.S. Fish and Wildlife Service (FWS) under the Pittman-Robertson Federal Aid in Wildlife Restoration Act, 16 U.S.C. 669 et seq. (Activities listed are not exclusive.)

Region 3

Michigan W-98-D

The goal of this project is to produce and maintain optimum wildlife habitat diversity on the state-owned land in the northern two-thirds of Michigan. Habitat development consists of the manipulation of plants and environments to produce a diversity of conditions most suited for numerous wildlife species. Several techniques or "tools" are utilized. These are: mechanical and manual cuttings of woody vegetation, commercial timber harvests, prescribe burning, herbicide sprays, herbaceous plantings, and woody plantings.

Region 6

Kansas FW-7-D

The purpose of this project is to protect, maintain, and enhance habitat conditions for fish and wildlife in north-central Kansas. Work will be conducted on 12 fish and wildlife management areas totaling 77,897 acres. Among project activities are construction of terraces, waterways, dams, roads, fences, public use facilities and building improvements; plantings of trees, shrubs, and herbaceous food and cover; and vegetation control including burning, mowing and timber thinning. Maintenance of buildings, roads, fences, dikes and dams, public use facilities and other area improvements is also included.

Kansas W-46-D

The purpose of this project is to develop and maintain habitat conditions and improvements at 11 wildlife areas totalling 39,676 acres in south-central Kansas. Among project activities are food and cover plots, tree and shrub plantings, development of roads, fences, dams, parking lots, and watershed improvements, vegetation control (burning and mechanical), timber clearing and management, water pumping and a land lease payment. Maintenance of existing roads, buildings, fences, dams, public use areas and other facilities is included.

Kansas W-48-D

This project covers development, operation and maintenance activities on 8 wildlife areas in southwestern Kansas. The project is designed to maintain a diversity of wildlife habitats on the various areas and ultimately to provide for public enjoyment of wildlife. Proposed activities include herbaceous seeding (food crops) and vegetation control, water level management, development of dikes, roads, signs, fences and public use facilities, project administration and maintenance of all existing habitat improvements and facilities.

Kansas W-49-D

The purpose of this project is habitat development and maintenance of existing conditions and facilities on 4 wildlife management areas totaling 42,866 acres in northeastern Kansas. Project activities include construction of one boat ramp, planting of trees and shrubs, millet seeding, native grass-legume cover plots, clearing, burning and water level management. Maintenance of roads, fences, buildings, dikes, public use facilities and other existing improvements is also planned.

Nebraska W-17-D

The purpose of this project is to develop, maintain and manage for wildlife production and public hunting on 68 wildlife areas totaling 87,178 acres statewide. Activities include vegetation control, planting of trees, food and cover crops, construction and maintenance work on roads, fences, erosion control dams, parking lots and waterfowl nesting structures.

South Dakota W-81-D

The purpose of this project is protection and enhancement of wildlife habitat and improvements on 526 wildlife areas totaling 145,473 acres statewide. Activities include herbaceous food and cover plantings, noxious vegetation control, tree planting, burning, fencing, parking area construction and waterfowl nest structures. Maintenance work involves roads, buildings, fences and public use facilities. Payments to landowners for retention of cover plots will be continued.

Utah W-117-LDR

This project provides for the development, operation and maintenance of 11 waterfowl management areas in the State of Utah and for research activities relating to the status, harvest, migration, mortality and habitat requirements of waterfowl populations in the State. Development and maintenance activities to be conducted include creation of potholes, herbaceous seeding and routine upkeep of buildings, dams, dikes, canals, roads and trails, fences, signs, and the management of water levels on the areas. In addition, the administration of the project, custodial functions and control and management of public use are included in the project. Research will be conducted through the use of aerial and ground surveys, questionnaires, hunter check stations, and other sampling procedures.

Wyoming W-52-D

Project purposes include development and maintenance activities to protect and enhance habitat conditions and access facilities on 24 Habitat Units totaling 233,144 acres statewide. Activities include fence construction, irrigation of meadows, trees and food patches, noxious vegetation control, water level manipulation, habitat use surveys, payment of taxes and land leases, and project administration. Maintenance of parking areas, roads, fences, dikes, nest structures, buildings, and other habitat and area improvements are also included.

ADDENDA

Region 1

Washington W-67-D (previously cited in July 20, 1979, Federal Register)

This project has been expanded to encompass wildlife habitat improvement activities on 96,000 additional acres of submarginal lands located in the Columbia Basin and primarily owned by the Bureau of Reclamation and the Energy Research and Development Administration. Activities include maintenance of roads, fences, signs, watering and emergency feeding systems. Wildlife food crops will also be planted.

Region 2

Arizona W-85-D (previously cited in July 20, 1979, Federal Register)

Supplement No. 1 to Arizona's Environmental Assessment for their Wildlife Area Maintenance and Operations Project W-85-D addresses the construction of a 3-foot dike to protect the headquarters at the Gila River Unit and the control of emergent aquatic vegetation on the Mittry Lake Unit.

Texas W-83-D (previously cited in July 20, 1979, Federal Register)

This supplement to the original Environmental Assessment dated February 9, 1979, addresses the construction of two boat storage buildings and three boat docks that are needed to provide protection to expensive equipment, to improve public access to the marsh compartments and to reduce erosion caused by the lack of docking facilities.

Region 4

Georgia W-37 (previously cited in July 20, 1979, Federal Register)

This project is concerned with research and survey activities conducted on a statewide basis to monitor the status of wildlife populations and to solve specific wildlife management problems. New activities recently added to the project will evaluate the effects of timber management on ruffed grouse; determine grouse habitat preferences; determine landowner attitudes toward hunting, fishing, and trapping; and determine black bear population dynamics.

Region 6

Iowa W-115-R (previously cited in September 6, 1979, Federal Register)

This multi-study research project deals with the collection of basic biological data on turkeys, pheasants, waterfowl, deer, coyotes and habitat-related activities. Besides surveys, questionnaires, radiotelemetry, etc., a small amount of habitat manipulation and vegetation control will also be conducted to determine the usefulness and impacts of different types of land uses and vegetation successional stages.

Dated: October 2, 1979.

Robert S. Cook,

Deputy Director, U.S. Fish and Wildlife Service.

[FR Doc. 79-30874 Filed 10-4-79; 8:45 am]

BILLING CODE 4310-55-M

National Park Service

[INT 79-56]

Availability of Draft Environmental Statement on Proposed General Management Plan for Stones River National Battlefield and Cemetery, Tennessee

Pursuant to Section 102(2)(C) of the National Environmental Policy Act of 1969, the Department of the Interior has prepared a Draft Environmental Statement on the proposed General Management Plan for Stones River National Battlefield and Cemetery.

The statement discusses proposals for the management, development and operation of Stones River National Battlefield and Cemetery.

Written comments on the environmental statement are invited and will be accepted for a period of sixty (60) days following publication of this notice. Comments should be addressed to the Regional Director, Southeast Region, or the Superintendent, Stones River National Battlefield and Cemetery, at the addresses given below.

Copies are available from or for inspection at the following locations:

Regional Director, Southeast Region, National Park Service, 1895 Phoenix Boulevard, Atlanta, Georgia 30349
Superintendent, Fort Donelson National Military Park, P.O. Box F, Dover, Tennessee 37058
Superintendent, Stones River National Battlefield and Cemetery, Route 10, Box 401, Old Nashville-Murfreesboro, Tennessee 37120

The U.S. Department of the Interior has determined that this document does not contain a major proposal requiring preparation of an Economic Impact Statement under Executive Order 11821, as amended by Executive Order 11949, and OMB Circular A-107.

Dated: September 26, 1979.

Larry E. Meierotto,

Assistant Secretary of the Interior.

[FR Doc. 79-30836 Filed 10-4-79; 8:45 am]

BILLING CODE 4310-70-M

DEPARTMENT OF STATE

Agency for International Development

[Delegation of Authority No. 1]

International Development Cooperation Agency; Foreign Economic Assistance

By virtue of the authority vested in me by the Foreign Assistance Act of 1961, as amended (22 U.S.C. 2151 *et seq.*) (hereinafter referred to as the Act), title IV of the International Development Cooperation Act of 1979 (22 U.S.C. 3501 *et seq.*), Executive Order No. 12163 of September 29, 1979 entitled "Administration of Foreign Assistance and Related Functions" (hereinafter referred to as the Executive Order), and Reorganization Plan No. 2 of 1979 (44 FR 41165), it is ordered as follows:

1-1. Concurrent Authority

1-101. Notwithstanding any provision of this Delegation of Authority, the Director of the United States International Development Cooperation Agency (hereinafter referred to as IDCA) may at any time exercise any function delegated by this Delegation of Authority.

1-2. Continuation of the Agency For International Development

1-201. The Agency for International Development (hereinafter referred to as AID), which was established in the Department of State pursuant to State Department Delegation of Authority No. 104, as amended, shall be continued in existence within IDCA headed by an Administrator (hereinafter referred to as the Administrator), as provided in sections 103(a) and 103(b) of the Executive Order. All delegations of authority, determinations, authorizations, regulations, rulings, certificates, orders, directives, contracts, agreements, designations, and other actions made, issued or entered into under authority existing prior to the date of the Executive Order and not revoked, superseded, or otherwise made inapplicable before the effective date of this Delegation of Authority shall continue in full force and effect until amended, modified or terminated by appropriate authority.

1-202. The officers provided for in section 1-103(c) of the Executive Order shall continue to exercise such functions as the Administrator deems appropriate.

1-3. Functions of the Administrator

1-301. Exclusive of the functions otherwise delegated, or reserved to the Director of IDCA herein, there are hereby delegated to the Administrator:

(a) The functions conferred upon the Director of IDCA by subsections 1-102(a) (1)-(4) and section 1-601 of the Executive Order.

(b) The functions and authorities contained in sections 125(a), 601 (a) through (d), and 601(e)(2) of the Act conferred upon the Director of IDCA by Section 6 of Reorganization Plan No. 2 of 1979.

1-4. Functions of the Director of the Institute for Scientific and Technological Cooperation

1-401. Exclusive of the functions otherwise delegated, or reserved to the Director of IDCA herein, there are hereby delegated to the Director of the Institute for Scientific and Technological Cooperation (hereinafter referred to as the Institute) the functions conferred upon the Director of IDCA by subsection 1-102(a)(5) of the Executive Order.

1-5. Functions Delegated to the Administrator and to the Director of the Institute

1-501. There are hereby delegated to the Administrator and to the Director of the Institute, respectively, the functions that relate to the administration of the programs of AID and the Institute, respectively, as follows:

(a) The functions under sections 297(d), 299(a) and 625(a) of the Act.

(b) The functions under section 625(d)(1) of the Act, as provided in section 1-602(a) of the Executive Order.

(c) The functions conferred upon the Director of IDCA by section 4 of Executive Order 11223, as amended.

(d) The functions conferred upon the Director of IDCA by the Determination of the President pursuant to section 604(a) of the Act, dated October 18, 1961, as amended.

(e) The functions of negotiating, concluding, and terminating international agreements pursuant to the Act, Title IV of the International Development Cooperation Act of 1979, or the Latin American Development Act, shall be subject to the requirements of 1 U.S.C. 112b and to applicable regulations and procedures.

1-6. Functions Delegated to the Overseas Private Investment Corporation

1-601. Exclusive of the functions otherwise delegated, or reserved to the Director of IDCA herein, there are hereby delegated to the Overseas Private Investment Corporation:

(a) The functions under sections 621(b), 625(d)(1), 627, 628, 629(b), 630 and 635(d) of the Act insofar as such functions relate to the operations of the Overseas Private Investment Corporation, its activities, or personnel.

(b) The functions under section 237(a) of the Act, provided that such functions shall be exercised in consultation with the Director of IDCA.

1-7. Allocation of Funds

1-701. There are hereby allocated to the Administrator all funds made available for carrying out the Act allocated to the Director of IDCA by section 1-801(a) of the Executive Order.

1-702. There are hereby allocated to the Director of the Institute all funds made available for carrying out title IV of the International Development Cooperation Act of 1979, allocated to the Director of IDCA by section 1-801(a) of the Executive Order.

1-8. Functions Reserved to the Director of IDCA

1-801. There are hereby reserved to the Director of IDCA the functions conferred upon the President by:

(a) Sections 102(c), 120(b), 125(b), 209(c)-(d), 298(c)(6), 298(d), 300, 305, 493, 621A, 631(c) and 634B of the Act.

(b) Section 625(a) of the Act, with respect to personnel in IDCA, other than as delegated in section 1-5 of this delegation.

(c) Sections 403(e) and 411 of the International Development Cooperation Act of 1979.

1-802. The functions contained in sections 109, 632(a) (insofar as they relate to allocation or transfer of funds) and 653 of the Act delegated herein shall be exercised in consultation with the Director of IDCA.

1-9. Foreign Service Personnel Authorities

1-901. The authority of the Foreign Service Act of 1946, as amended, to appoint, employ, and assign personnel, which the Director of IDCA, the Administrator and the Director of the Institute are authorized to exercise pursuant to section 625(d)(2) of the Act, and the provisions of the Foreign Service Act which apply to personnel so appointed or assigned shall consist of:

(a) The authority available to the Secretary of State under the Foreign Service Act of 1946 (including section 571 of that Act) relating to Foreign Service Reserve officers, Foreign Service Staff officers and employees, and alien clerks and employees.

(b) The authority available to the Secretary of State under sections 1021 through 1071 of the Foreign Service Act of 1946.

(c) The authority available to the Board of Foreign Service and under the Foreign Service Act of 1946.

(d) The authority to prescribe or issue in pursuance of Foreign Service Act of 1946 and the Act, such regulations, orders and instructions, as may be incidental to, or necessary for, or desirable in connection with, the carrying out of the provisions of section 625(d)(2) of the Act or the provisions of this Delegation of Authority.

(e) The prohibitions contained in sections 1001 through 1005 of the Foreign Service Act of 1946.

1-10. General Provisions

1-1001. Any reference in this Delegation of Authority to any act, order, determination, or delegation of authority shall be deemed to be a reference to such act, order, determination, or delegation of authority as amended from time to time.

1-1002. Any reference in this Delegation of Authority to provisions of any appropriation act shall be deemed to include a reference to any hereafter enacted provisions of law which are the same or substantially the same as much appropriation act provisions.

1-1003. The Administrator and the Director of the Institute may, to the extent consistent with law:

(a) Delegate or assign any of the functions delegated or assigned to them by this Delegation of Authority to any other officer of IDCA, including any component agency thereof, or to any officer of the Department of State; and

(b) Authorize any officer to whom functions are so delegated or assigned to successively redelegate or reassign any of such functions.

1-1004. Functions conferred by this delegation shall be carried out in consultation with the heads of other departments and agencies as provided in Section 605 of the Executive Order.

1-11. Effective Date

1-1101. This delegation shall become effective as of October 1, 1979, except that delegations to the Director of the Institute contained herein shall not become effective until so ordered by the Director of IDCA.

Thomas Ehrlich,

Director, United States International Developoment Cooperation Agency.

Dated: October 1, 1979.

[FR Doc. 79-30924 Filed 10-4-79; 8:45 am]

BILLING CODE 4710-02-M

DEPARTMENT OF JUSTICE

Advisory Committee on Tax Litigation; Open Meeting

Pursuant to the Federal Advisory Committee Act of October 6, 1972 (Pub. L. 92-463, 86 Stat. 770-776, 5 U.S.C. App. I, Supp. II) notice is hereby given that there will be a meeting of the Advisory Committee on Tax Litigation on October 22, 1979, in Room 4107 of the Main Justice Building. The building is located between Pennsylvania and Constitution Avenues N.W. and Ninth and Tenth Streets, Washington, D.C. The meeting will begin at 9:30 a.m. The Agenda will include the following topics:

Increased Use of Grand Juries in Tax Investigations: Possible Abuse Where Taxpayer Proposes to Claim the 5th Amendment Privilege or Resist a Summons
Use of Search Warrants to Professional Advisers in Criminal Tax Cases
Government Policy on Multiple Representation
Power of Revenue Agents to Grant Immunity in Criminal Tax Cases
Format and Content of Conference with Tax Division in Criminal Tax Cases
Required Records Doctrine as an Exclusion to 5th Amendment Privilege and Privilege of Confidentiality—Does the Exclusion Require Limits?
Standards for Pre-Indictment Consideration of Existence of Mental Disorder as Relevant to Willfulness or Intent in Criminal Tax Cases
Coordination Between Tax Division and Internal Revenue Service in Administrative Processing and Settlement, Particularly in Court of Claims Cases
Should a "Tax Docket Judge" be Established in District Courts?
Should Discovery Rules in Court of Claims Conform to the FRCP?
Venue Changes in § 6672 (Responsible Persons) Cases, Including Transferability Into and Out of the Court of Claims—What Proposals Would Be Appropriate?
Statutory Deadlines of § 7429 (Jeopardy Assessment Suits)—Should They Be Modified?
Review Procedure for Issuing Summons of Tax Reserve Papers
Declaratory Judgments—Should Currently Allowed Actions Be Extended to All Three Courts with Tax Jurisdiction? Is Congress Over Extending the Declaratory Judgment Technique? Should the Parties Be Able to Go Beyond the Administrative Record?
Award of Legal Fees in Tax Cases
Role of Tax Division In Regard to Legislative and Administrative Responsibilities of the Treasury and IRS
Litigation Proposals—National Court of Tax Appeals and Court of Claims Jurisdiction
Current Upward Trend in Interest Rates—Should Statutory Interest Rates be Reexamined? Should There Be a "Floating Relationship" Between These Statutory Rates and Commercial Prime Rates?

The Members of the Advisory Committee on Tax Litigation are:

Mary Ann Cohen (Los Angeles, Calif.)
Thomas F. Field (Washington, D.C.)
Charles W. Hall (Houston, Texas)
William Holloran (New York, N.Y.)
Boris Kostelanetz (New York, N.Y.)
Charles S. Lyon (New York, N.Y.)
Harry K. Mansfield (Boston, Mass.)
Lipman Redman (Washington, D.C.)
Harvey M. Silets (Chicago, Ill.)
Sherwin Simmons (Tampa, Fla.)
Samuel C. Thompson, Jr. (Charlottesville, Va.)
Charles M. Walker (Los Angeles, Calif.)

The meeting, which will be open to the public, will be in a room that accommodates approximately 50 people. After the Committee members finish discussing the items on the agenda, there may be time for statements by nonmembers. If you want to make a statement at the meeting, or if you would like the Committee to consider a written statement, please call or write to the Special Assistant to the Assistant Attorney General, Tax Division, Department of Justice, Washington, D.C. 20530.

For further information contact: Special Assistant to the Assistant Attorney General, Tax Division, Department of Justice, 202-633-3967 (not toll free).

Dated: September 29, 1979.

M. Carr Ferguson,
Assistant Attorney General, Tax Division, Department of Justice.

[FR Doc. 79-30921 Filed 10-4-79; 8:45 am]
BILLING CODE 4410-01-M

National Institute of Corrections

Hearings

The Advisory Board of the National Institute of Corrections (NIC), U.S. Department of Justice, will hold five public hearings throughout the country to ascertain the priority needs of corrections and guide the agency's program planning for fiscal years 1981 and 1982.

Each two-day hearing will consist of a series of two-hour panels. On each panel will be a representative of the legal profession, an institutional worker or administrator; a representative of probation or parole; a citizen and/or advocate; a theoretician or academic; a correctional planner or project director; and a state corrections commissioner. Participants will comment on the needs of corrections that NIC can address through funding.

The hearings are scheduled as follows:

October 10 and 11, 1979

Sheraton—Denver Airport, 3535 Quebec Street, Denver, Colorado

October 17 and 18, 1979

University of Chicago Law School, Court Room Building, 111 East 60th Street, Chicago, Illinois

October 24 and 25, 1979

Carnegie International Center, 345 East 46th Street, Room 207, New York, New York

November 6 and 7, 1979

Federal Correctional Institution, Terminal Island, Long Beach, California

December 4 and 5, 1979

Georgia State University, University Plaza, Urban Life Center, Room 307, Corner of Decatur and Peachtree Streets, Atlanta, Georgia

To begin at 8:30 a.m. each day, the hearings are open to the public. For more information, contact Nancy Sabanosh at the National Institute of Corrections, 320 First St., N.W., Washington DC, 20534; telephone (202) 724-3106.

Dated: October 1, 1979.

Robert L. Smith,
Assistant Director, National Institute of Corrections.

[FR Doc. 79-30837 Filed 10-4-79; 8:45 am]
BILLING CODE 4410-05-M

DEPARTMENT OF LABOR

Office of the Secretary

Investigations Regarding Certifications of Eligibility To Apply for Worker Adjustment Assistance

Petitions have been filed with the Secretary of Labor under Section 221(a) of the Trade Act of 1974 ("the Act") and are identified in the Appendix to this notice. Upon receipt of these petitions, the Director of the Office of Trade Adjustment Assistance, Bureau of International Labor Affairs, has instituted investigations pursuant to Section 221(a) of the Act and 29 CFR 90.12.

The purpose of each of the investigations is to determine whether absolute or relative increases of imports of articles like or directly competitive with articles produced by the workers' firm or an appropriate subdivision thereof have contributed importantly to an absolute decline in sales or production, or both, of such firm or subdivision and to the actual or threatened total or partial separation of a significant number or a proportion of the workers of such firm or subdivision.

Petitioners meeting these eligibility requirements will be certified as eligible to apply for adjustment assistance under Title II, Chapter 2, of the Act in accordance with the provisions of Subpart B of 29 CFR Part 90. The investigations will further relate, as appropriate, to the determination of the date on which total or partial separations began or threatened to begin and the subdivision of the firm involved.

Pursuant to 29 CFR 90.13, the petitioners or any other persons showing a substantial interest in the subject matter of the investigations may request a public hearing, provided such request is filed in writing with the Director, Office of Trade Adjustment Assistance, at the address shown below, not later than October 15, 1979.

Interested persons are invited to submit written comments regarding the subject matter of the investigations to the Director, Office of Trade Adjustment Assistance, at the address shown below, not later than October 15, 1979.

The petitions filed in this case are available for inspection at the Office of the Director, Office of Trade Adjustment Assistance, Bureau of International Labor Affairs, U.S. Department of Labor, 200 Constitution Avenue, N.W., Washington, D.C. 20210.

Signed at Washington, D.C. this 27th day of September 1979.

Marvin M. Fooks,

Director, Office of Trade Adjustment Assistance.

Appendix

Petitioner: Union/workers or former workers of—	Location	Date received	Date of petition	Petition No.	Articles produced
Allegheny Buffalo China, Inc. (company)	Clarendon, Pa	Sept. 24, 1979	Sept. 20, 1979	TA-W-6,109	Holloware (cups and bowls).
Alpha Metals (teamsters)	Jersey City, N.J	Sept. 24, 1979	Sept. 19, 1979	TA-W-6,110	Solder-flux-gold plating.
Buffalo China, Inc. (company)	Buffalo, N.Y	Sept. 24, 1979	Sept. 20, 1979	TA-W-6,111	Chinaware and holloware.
Devon, Inc. (ACTWU)	Thurmont, Md	Aug. 27, 1979	Aug. 21, 1979	TA-W-6,112	Custom tailored men's clothing.
Farama Manufacturing Co., Inc. (workers)	Springfield Gardens, N.Y	Sept. 11, 1979	Sept. 4, 1979	TA-W-6,113	Women's sportswear.
Haas Tailoring Co. (ACTWU)	Baltimore, Md	Aug. 27, 1979	Aug. 21, 1979	TA-W-6,114	Custom tailored men's clothes.
Joseph Herman Shoe Company of Maine (workers).	Scarborough, Maine	Sept. 24, 1979	Sept. 21, 1979	TA-W-6,115	Leather work boots and shoes.
The Youngstown Mine Corp., Duhue Mine (workers).	Duhue, W. Va	Sept. 20, 1979	Sept. 17, 1979	TA-W-6,116	Metallurgical coal.
Townsend Fastening System (USWA)	Fallston, Pa	Sept. 24, 1979	Sept. 19, 1979	TA-W-6,117	Industrial fastners.
Townsend Fastening System (USWA)	Ellwood City, Pa	Sept. 24, 1979	Sept. 19, 1979	TA-W-6,118	Industrial fastners.

[FR Doc. 79-30962 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5799 and 5800]

Barnes & Tucker Co.; Notice of Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on July 31, 1979 in response to a worker petition received on July 30, 1979 which was filed by the United Mine Workers of America on behalf of workers and former workers mining metallurgical coal at mines #20 and #25 of the Barnes and Tucker Company, Barnesboro, Pennsylvania. In the following determination, without regard to whether any of the other criteria have been met, the following criterion has not been met:

That increases of imports of articles like or directly competitive with articles produced by the firm or appropriate subdivision have contributed importantly to the separations, or threat thereof, and to the absolute decline in sales or production.

With respect to mine #20, evidence developed during the course of the investigation revealed that since early 1978, all of the output from that mine has been exported.

The Department's investigation revealed that no significant declines in employment occurred in 1978 or in the first quarter of 1979. The small declines which did occur during this period are attributable to voluntary separations.

Involuntary separations at mine #20 began in April 1979. However, all of the coal mined from mine #20 since early 1978 has been exported. Therefore, any imports of coal or coke during this period would have no effect on sales, production and employment at mine #20 of Barnes and Tucker Company.

With respect to mine #25, evidence developed during the course of the investigation revealed that the company for which Barnes and Tucker mined coal at this site decreased its purchases of imported coke and increased its purchases of domestic metallurgical coal.

Barnes and Tucker Company operates mine #25 under contract for another company. This company did not purchase any imported coal in 1978 or the first half of 1979 and its purchases of domestic metallurgical coal increased during this period. Increased purchases of domestic metallurgical coal from 1977 to 1978 and in the first seven months of 1979 compared to the first seven months of 1978 indicate increased domestic coke production by this company. While this company does purchase imported coke, purchases of foreign coke decreased from 1977 to 1978 and in the first seven months of 1979 compared to the first seven months of 1978.

Conclusion

After careful review, I determine that all workers of mines #20 and #25 of the Barnes and Tucker Company, Barnesboro, Pennsylvania are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 28th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30963 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5829]

Bonnell Dress Co.; Notice of Termination of Investigation

Pursuant to Section 221 of the Trade Act of 1974, an investigation was initiated on August 8, 1979 in response to a worker petition received on August 6, 1979 which was filed on behalf of workers and former workers producing ladies' dresses at Bonnell Dress Company in Moorestown, New Jersey.

The petitioner requested withdrawal of the petition in a letter. On the basis of the withdrawal, continuing the investigation would serve no purpose. Consequently, the investigation has been terminated.

Signed at Washington, D.C. this 27th day of September 1979.

Marvin M. Fooks,

Director, Office of Trade Adjustment Assistance.

[FR Doc. 79-30964 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5899]

Brady Marine Repair Co., Inc.; Notice of Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presens the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on August 27, 1979, in response to a worker petition received on August 21, 1979, which was filed by the Industrial Union of Marine & Shipbuilding Workers of America on behalf of workers and former workers of Brady Marine Repair Company, Elizabeth, New Jersey, engaged in conversion, repair, overhaul, and maintenance of marine vessels. The investigation revealed that the legal title of the firm is Brady Marine Repair Company, Incorporated.

Brady Marine Repair Company, Incorporated is engaged in providing the service of repairing ships.

Thus, workers of Brady Marine Repair Company, Incorporated do not produce an article within the meaning of Section 222(3) of the Act. Therefore, they may be certified only if their separation was caused importantly by a reduced demand for their services from a parent firm, a firm otherwise related to Brady Marine Repair Company, Incorporated by ownership, or a firm related by control. In any case, the reduction in demand for services must originate at a production facility whose workers independently meet the statutory criteria for certification and that reduction must directly relate to the product impacted by imports.

Brady Marine Repair Company, Incorporated and its customers have no controlling interest in one another. The subject firm is not corporately affiliated with any other company.

All workers engaged in repairing ships at Brady Marine Repair Company, Incorporated are employed by that firm. All personnel actions and payroll transactions are controlled by Brady Marine Repair Company, Incorporated. All employee benefits are provided and maintained by Brady Marine Repair Company, Incorporated. Workers are not, at any time, under employment or supervision by customers of Brady Marine Repair Company, Incorporated. Thus, Brady Marine Repair Company, Incorporated, and not any of its customers, must be considered to be the "workers' firm".

Conclusion

After careful review, I determine that all workers of Brady Marine Repair Company, Incorporated, Elizabeth, New Jersey are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 27th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30965 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-4903, 4904, and 5035]

Cluett, Peabody & Co., Inc. the Arrow Co. Division; Revised Determinations of Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974, the Department of Labor issued a Certification of Eligibility to Apply for Adjustment Assistance on May 4, 1979, applicable to all workers of The Arrow Company Division plants at Virginia and Eveleth, Minnesota, of the Cluett, Peabody and Co., Inc. The Notice of Certification was published in the Federal Register on May 11, 1979, (44 FR 27766). On May 21, 1979, the Department issued a Notice of Negative Determination Regarding Eligibility to Apply for Adjustment Assistance for all workers of the Eveleth II plant, Eveleth, Minnesota, (44 FR 30487). On July 5, 1979, the Department issued a Notice of Negative Determination Regarding Application for Reconsideration (44 FR 40968-69).

On the basis of additional information, the Office of Trade Adjustment Assistance, on its own motion, reviewed the negative determination. The Department made additional inquiries and its further review revealed that underwear workers at The Arrow Company Division's plant at Eveleth II, Eveleth, Minnesota, were regularly sent to Eveleth I to work on shirt operations in 1978 when work at Eveleth II was slow. Further, some shirt operations from Eveleth I were transferred to Eveleth II. According to a company official, workers at Eveleth II spent a significant proportion of their time on shirt operations in 1978.

The intent of the certification is to cover all workers of Cluett, Peabody and Company's Arrow Division's plants in Virginia, Minnesota, and Eveleth, Minnesota, who were affected by the decline in production of men's dress shirts related to import competition. The determiniations, therefore, are revised to include workers engaged in employment related to production of men's shirts at The Arrow Company Division's Eveleth II plant in Eveleth, Minnesota.

The determinations applicable to TA-W-4903, 4904, and 5035 are hereby revised as follows:

All workers at the Virginia, Minnesota, plant of The Arrow Company Division of Cluett, Peabody and Co., Inc., who became totally or partially separated from employment on or after April 1, 1978; all workers at the Eveleth I plant, Eveleth, Minnesota, of The Arrow Company Division of Cluett, Peabody and Co., Inc., who became totally or partially separated from employment on or after August 1, 1978; and all workers at the Eveleth II plant, Eveleth, Minnesota, of The Arrow Company Division of Cluett, Peabody and Co., Inc., engaged in employment related to the production of men's shirts who became totally or partially separated from employment on or after August 1, 1978, and before May 4, 1981, are eligible to apply for adjustment asistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed At Washington, D.C., this 27th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30966 Filed 10-04-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5902]

Coastal Dry Dock & Repair Corp.; Notice of Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 USC 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on August 27, 1979, in response to a worker petition received on August 21, 1979, which was filed by the Industrial Union of Marine and Shipbuilding Workers of America on behalf of workers and former workers of Coastal Dry Dock and Repair Corporation, Brooklyn, New York, engaged in conversion, repair, overhaul, and maintenance of Navy vessels.

Coastal Dry Dock and Repair Corporation is engaged in providing the service of ship conversion and repair.

Thus, workers of Coastal Dry Dock and Repair Corporation do not produce an article within the meaning of Section 222(3) of the Act. Therefore, they may be certified only if their separation was caused importantly by a reduced demand for their services from a parent firm, a firm otherwise related to Coastal Dry Dock and Repair Corporation by ownership, or a firm related by control. In any case, the reduction in demand for services must originate at a production facility whose workers independently meet the statutory criteria for certification and that reduction must directly relate to the product impacted by imports.

Coastal Dry Dock and Repair Corporation and its customers have no controlling interest in one another. The subject firm is not corporately affiliated with any other company.

All workers engaged in ship conversion and repair at Coastal Dry Dock and Repair Corporation are employed by that firm. All personnel actions and payroll transactions are controlled by Coastal Dry Dock and Repair Corporation. All employee benefits are provided and maintained by Coastal Dry Dock and Repair Corporation. Workers are not, at any time, under employment or supervision by customers of Coastal Dry Dock and Repair Corporation. Thus, Coastal Dry Dock and Repair Corporation, and not any of its customers, must be considered to be the "workers' firm".

Conclusion

After careful review, I determine that all workers of Coastal Dry Dock and Repair Corporation, Brooklyn, New York are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 28th day of September 1979.

Harry J. Gilman,

Supervisory International Economist, Office of Foreign Economic Research.

[FR Doc. 79-30367 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5934]

Commercial Carriers, Inc.; Notice of Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 USC 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on August 30, 1979, in response to a worker petition received on August 27, 1979, which was filed by the International Brotherhood of Teamsters, Chauffeurs, Warehousemen and Helpers of America on behalf of workers and former workers of Commercial Carriers, Incorporated, Nashville Terminal, Nashville, Tennessee, engaged in transporting automobiles.

Commercial Carriers, Incorporated is engaged in providing the service of transporting automobiles and trucks from railheads to automobile dealers.

Thus, workers of Commercial Carriers, Incorporated do not produce an article within the meaning of Section 222(3) of the Act. Therefore, they may be certified only if their separation was caused importantly by a reduced demand for their services from a parent firm, a firm otherwise related to Commercial Carriers, Incorporated by ownership, or a firm related by control. In any case, the reduction in demand for services must originate at a production facility whose workers independently meet the statutory criteria for certification and that reduction must directly relate to the product impacted by imports.

Commercial Carriers, Incorporated and its customers have no controlling interest in one another. The subject firm, although affiliated with a producer of marine equipment, does not transport products of that or any other affiliated comany.

All workers engaged in transporting automobiles and trucks at Commercial Carriers, Incorporated, Nashville Terminal are employed by that firm. All personnel actions and payroll transactions are controlled by Commercial Carriers, Incorporated. All employee benefits are provided and maintained by Commercial Carriers, Incorporated. Workers are not, at any time, under employment or supervision by customers of Commercial Carriers, Incorporated. Thus, Commercial Carriers, Incorporated, Nashville Terminal and not any of its customers, must be considered to be the "workers' firm".

Conclusion

After careful review, I determine that all workers of Commercial Carriers, Incorporated, Nashville Terminal, Nashville Tennessee are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 28th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30368 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5821]

Curlee Clothing Co., Inc.; Notice of Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 USC 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on August 7, 1979, in response to a worker petition received on August 3, 1979, which was filed on behalf of workers and former workers producing men's suits, sportcoats, vest and slacks at Curlee Clothing Company, Incorporated, St. Louis, Missouri. The investigation revealed that the St. Louis location acted as headquarters for Curlee and was not involved with any production activities. In the following determination, without regard to whether any of the other criteria have been met, the following criterion has not been met:

That increases of imports of articles like or directly competitive with articles produced by the firm or appropriate subdivision have contributed importantly to the separations, or threat thereof, and to the absolute decline in sales or production.

Evidence developed during the course of the investigation revealed that workers at the St. Louis, Missouri headquarters of Curlee Clothing

Company were separated from employment due to the transfer of the headquarters from St. Louis, Missouri to Lexington, Kentucky.

The St. Louis headquarters was responsible for the administrative and management activities of Curlee Clothing Company. On July 5, 1979 the headquarters moved to Lexington, Kentucky to be closer to the company's sole production facility in Winchester, Kentucky. All personnel at the St. Louis facility were given the option to transfer.

Conclusion

After careful review, I determine that all workers of Curlee Clothing Company, Incorporated, St. Louis, Missouri are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 28th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30969 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5785]

Dartmouth Finishing Corp.; Notice of Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on July 30, 1979 in response to a worker petition received on July 26, 1979 which was filed by the Machine Printers and Engravers Association on behalf of workers and former workers printing textiles at Dartmouth Finishing Corporation, New Bedford, Massachusetts. In the following determinations, without regard to whether any of the other criteria have been met, the following criterion has not been met:

That increases of imports of articles like or directly competitive with articles produced by the firm or appropriate subdivision have contributed importantly to the separations, or threat thereof, and to the absolute decline in sales or production.

U.S. imports of finished fabric (bleached, dyed, and printed) decreased during the first half of 1979 compared with the first half of 1978. The ratios of imports to domestic production and consumption have been 2 percent or less in each year since 1974.

The Department conducted a survey of Dartmouth Finishing Corporation's customers concerning their purchases of finished fabric. Survey respondents reported they neither purchased imported fabric, nor contracted printing with foreign firms.

Conclusion

After careful review, I determine that all workers of Dartmouth Finishing Corporation, New Bedford, Massachusetts are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C., this 28th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30970 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5936]

Dexter Buick-GMC Truck Co., Inc.; Notice of Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on August 30, 1979, in response to a worker petition received on August 15, 1979, which was filed on behalf of workers and former workers of Dexter Buick-GMC Truck Company, Incorporated, Providence, Rhode Island, an auto dealership.

Dexter Buick-GMC Truck Company, Incorporated is engaged in providing the service of selling and servicing automobiles and trucks.

Thus, workers of Dexter Buick-GMC Truck Company, Incorporated do not produce an article within the meaning of Section 222(3) of the Act. Therefore, they may be certified only if their separation was caused importantly by a reduced demand for their services from a parent firm, a firm otherwise related to Dexter Buick-GMC Truck Company, Incorporated by ownership, or a firm related by control. In any case, the reduction in demand for services must originate at a production facility whose workers independently meet the statutory criteria for certification and that reduction must directly relate to the product impacted by imports.

Dexter Buick-GMC Truck Company, Incorporated and its customers have no controlling interest in one another. The subject firm is not corporately affiliated with any other company.

All workers engaged in selling and servicing automobiles and trucks at Dexter Buick-GMC Truck Company, Incorporated are employed by that firm. All personnel actions and payroll transactions are controlled by Dexter Buick-GMC Truck Company, Incorporated. All employee benefits are provided and maintained by Dexter Buick-GMC Truck Company, Incorporated. Workers are not, at any time, under employment or supervision by customers of Dexter Buick-GMC Truck Company, Incorporated. Thus, Dexter Buick-GMC Truck Company, Incorporated, and not any of its customers, must be considered to be the "workers' firm".

Conclusion

After careful review, I determine that all workers of Dexter Buick-GMC Truck Company, Incorporated, Providence, Rhode Island are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C., this 28th day of September 1979.

Harry J. Gilman,

Supervisory International Economist, Office of Foreign Economic Research.

[FR Doc. 79-30971 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

TA-W-5787

Duro Textile Printers, Inc.; Notice of Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 USC 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance, each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on July 30, 1979 in response to a worker petition received on July 26, 1979 which was filed by the Machine Printers and Engravers Association on behalf of workers and former workers printing textiles at Duro Textile Printers, Incorporated, Fall River, Massachusetts. In the following determination, without regard to whether any of the criteria have been met, the following criterion has not been met:

That increases of imports of articles like or directly competitive with articles produced by the firm or appropriate subdivision have contributed importantly to the separations, or threat thereof, and to the absolute decline in sales or production.

U.S. imports of finished fabric (bleached, dyed, and printed) decreased during the first half of 1979 compared with the first half of 1978. The ratios of imports to domestic production and consumption have been 2 percent or less in each year since 1974.

The Department conducted a survey of customers of Duro Textile Printers, Incorporated concerning their purchases of finished fabric. None of the survey respondents reported decreasing contract printing orders with Duro Textile and increasing contract work with foreign firms or increasing imports of finished fabric.

Conclusion

After careful review, I determine that all workers of Duro Textile Printers, Incorporated, Fall River, Massachusetts are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C., this 28th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30972 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5867]

E & W of Paragould, Inc.; Notice of Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 USC 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on August 17, 1979 in response to a worker petition received on August 10, 1979 which was filed on behalf of workers and former workers producing men's and boys' shirts at E & W of Paragould, Incorporated, Paragould, Arkansas. In the following determination, without regard to whether any of the criteria have been met, the following criterion has not been met:

That increases of imports of articles like or directly competitive with articles produced by the firm or appropriate subdivision have contributed importantly to the separations, or threat thereof, and to the absolute decline in sales or production.

The average number of production workers increased in 1978 compared with 1977, and increased during January through July 1979 compared with the same period in 1978. Average quarterly employment increased in every quarter compared with the same quarter of the previous year from the second quarter of 1978 through the first quarter of 1979 and did not decline significantly in the second quarter of 1979. Employment fluctuations within these periods are consistent with the firm's normal seasonal trend of production. There is no immediate threat of separation of workers at the firm.

Conclusion

After careful review, I determine that all workers of E & W of Paragould, Incorporated, Paragould, Arkansas are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 28th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30973 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

TA-W-5803

Foster Grant Corp.; Certification Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance, each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on July 31, 1979 in response to a worker petition received on July 27, 1979 which was filed by the Retail, Wholesale and Department Store Union on behalf of workers and former workers producing sunglasses at Foster Grant Corporation, Leominster, Massachusetts. It is concluded that all of the requirements have been met.

U.S. imports of sunglasses increased in quantity in 1978 from 1977. The ratio of imports to domestic production increased in 1978 from 1977 and increased in January–June 1979 compared to the same period in 1978.

Company imports of component parts for sunglasses and finished sunglasses increased in 1978 from 1977 and increased in January–July 1979 compared to the like period in 1978.

Conclusion

After careful review of the facts obtained in the investigation, I conclude that increases of imports of articles like or directly competitive with sunglasses produced at Foster Grant Corporation, Leominster, Massachusetts contributed importantly to the decline in sales or production and to the total or partial separation of workers of that firm. In accordance with the provisions of the Act, I make the following certification:

All workers of Foster Grant Corporation, Leominster, Massachusetts engaged in employment related to the production of sunglasses, who became totally or partially separated from employment on or after July 25, 1978 are eligible to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C., this 28th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30974 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

TA-W-5822

Fred Engelman Co., Inc.; Certification Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 USC 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance, each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on August 7, 1979 in response to a worker petition received on August 6, 1979 which was filed on behalf of workers and former workers producing novelty tops and blouses at the Fred Engelman Company, Incorporated, New York, New York. The investigation revealed that the plant also produces dresses and skirts. It is concluded that all of the requirements have been met.

U.S imports of women's, misses' and children's blouses and shirts increased absolutely in each year from 1975 through 1977 compared to the preceding year. U.S. imports increased relative to domestic production in 1978 compared to 1977.

U.S. imports of women's and misses' dresses increased absolutely and relative to domestic production in 1978 compared to 1977.

U.S. imports of women's, misses' and children's skirts increased absolutely and relative to domestic production in 1978 compared to 1977.

A Departmental survey was conducted with the retail customers of Fred Engelman Company. Customers representing a significant portion of Fred Engelman's sales decreased purchases of ladies' blouses and skirts from Fred Engelman Company in 1978 compared to 1977 and in the January–May 1979 period compared to the same period of 1978. These customers increased purchases of imported ladies' blouses and skirts during the same time periods.

Conclusion

After careful review of the facts obtained in the investigation, I conclude that increases of imports of articles like or directly competitive with novelty tops and blouses and skirts produced at the Fred Engelman Company, Incorporated, New York, New York contributed importantly to the decline in sales or production and to the total or partial separation of workers of that firm. In accordance with the provisions of the Act, I make the following certification:

> All workers of the Fred Engelman Company, Incorporated, New York, New York who became totally or partially separated from employment on or after July 16, 1978 are eligible to apply for adjustment assistance under Title II, Chapter 2 of the Trade act of 1974.

Signed at Washington, D.C., this 28th day of September 1979.

C. Michael Aho,

Director, Office of Foreign Economic Research.

[FR Doc. 79-30975 Filed 10-04-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-6064]

Hawley Coal Mining Corp.; Notice of Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on September 20, 1979 in response to a worker petition received on September 17, 1979 which was by the United Mine Workers of America on behalf of workers and former workers mining coal at Hawley Coal Mining Corporation, Keystone, West Virginia. The investigation revealed that coal is mined at the Pocahontas Empire Bottom Creek Mine, Blue Boy #6 Mine and #10 Bradshaw Mine and is cleaned at the Pocahontas Empire Preparation Plant of Hawley Coal Mining Corporation, McDowell County, West Virginia. Without regard to whether any of the other criteria have been met, the following criterion has not been met:

> That increases of imports of articles like or directly competitive with articles produced by the firm or appropriate subdivision have contributed importantly to the separations, or threat thereof, and to the absolute decline in sales or production.

Evidence developed in the course of the investigation revealed that Hawley Coal Mining Corporation was sold by Belco Petroleum Corporation in 1976. Since that time, all metallurgical coal mined by the three mines of Hawley Coal Mining Corporation and its four contractors has been exported to France. Hawley Coal Mining Corporation has no domestic customers.

Conclusion

After careful review, I determine that all workers of the Pocahontas Empire (Bottom Creek) Mine and Preparation Plant, the Blue Boy #6 Mine and #10 Bradshaw Mine of Hawley Coal Mining Corporation, McDowell County, West Virginia are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 27th day of September 1979.

Harry J. Gilman,

Supervisory International Economist, Office of Foreign Economic Research.

[FR Doc. 79-30976 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

TA-W-5868

Herman Funke & Sons, Inc.; Notice of Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on August 17, 1979 in response to a worker petition received on August 13, 1979 which was filed by the United Textile Workers of America on behalf of workers and former workers producing schiffli embroideries at Herman Funke & Sons, Incorporated in Ashley, Pennsylvania. In the following determination, without regard to whether any of the other criteria have been met, the following criterion has not been met:

> That increases of imports of articles like or directly competitive with articles produced by the firm or appropriate subdivision have contributed importantly to the separations, or threat thereof, and to the absolute decline in sales or production.

U.S. imports of ornamented fabrics, including embroideries, declined in the January-June period of 1979 compared to the same period of 1978. The ratio of imports to domestic production was less than one percent in each year from 1974 through 1978.

A survey was conducted by the Department of Labor of customers of Herman Funke & Sons, Incorporated. The survey revealed that most customers did not purchase imported embroideries and lace goods. Customers which did import embroideries and lace goods amounted to an insignificant proportion of Herman Funke's sales in 1978 and in the first seven months of 1979.

Conclusion

After careful review, I determine that all workers of Herman Funke & Sons, Incorporated, Ashley, Pennsylvania are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 28th day of September 1979.

Harry J. Gilman,

Supervisory International Economist, Office of Foreign Economic Research.

[FR Doc. 79-30977 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

TA-W-5815

Howard Stores Corp.; Certification Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance, each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on August 3, 1979 in response to a worker petition received on July 20, 1979 which was filed by the Amalgamated Clothing and Textile Workers Union on behalf of workers and former workers producing men's tailored clothing at Howard Stores Corporation, Brooklyn, New York. It is concluded that all of the requirements have been met.

Evidence developed during the course of the investigation revealed that U.S. imports of men's and boys' tailored dress coats and sportcoats increased both absolutely and relative to domestic production in 1978 compared to 1977.

U.S. imports of men's and boys' tailored suits increased absolutely and relatively in 1977 compared to 1976 before decreasing slightly in 1978.

Most of Howard Stores Corporation's production during 1978 and the first half of 1979 was for a men's clothing manufacturer. In a survey conducted by the Department of Commerce, customers of this manufacturer, accounting for a significant proportion of the manufacturer's sales decline, indicated that they had decreased purchases from the manufacturer and had increased purchases of imported men's suits and sportcoats. The U.S. Department of Commerce certified this manufacturer as eligible to apply for firm adjustment assistance on July 19, 1979.

Conclusion

After careful review of the facts obtained in the investigation, I conclude that increases of imports of articles like or directly competitive with men's tailored clothing produced at Howard Stores Corporation,, Brooklyn, New York contributed importantly to the decline in sales or production and to the total or partial separation of workers of that firm. In accordance with the provisions of the Act, I make the following certification:

All workers of Howard Stores Corporation, Brooklyn, New York who became totally or partially separated from employment on or after February 23, 1979 are eligible to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 28th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30978 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5804 and 5805]

Jeep Corp.; Notice of Determinations Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance, each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on July 31, 1979, in response to a worker petition received on July 27, 1979, which was filed by the United Automobile, Aerospace and Agricultural Implement Workers of America on behalf of workers and former workers producing jeep vehicles at the North Cove Boulevard plant (TA-W-5804) and machining engines at the Stickney Avenue plant (TA-W-5805) in Toledo, Ohio of the Jeep Corporation. The investigation revealed that the North Cove Boulevard and Stickney Avenue plants are part of one Toledo, Ohio facility. Also, all jeep vehicles are four-wheel drive and come under one of three vehicle categories: general utility type, station-wagon type and pick-up truck type. In the following determination without regard to whether any of the other criteria have been met for workers assembling Jeep four-wheel drive station-wagon and general utility vehicles, the following citerion has not been met.

That increases of imports of articles like or directly competitive with articles produced by the firm or appropritate subdivision have contributed importantly to the separations, or threat thereof, and to the absolute decline in sales or production.

The Jeep Corporation produces two models of four-wheel drive station-wagon vehicles (the Cherokee and Wagoneer) at the Toledo, Ohio plant, both 6,000 pounds or more in weight. There are no U.S. imports of vehicles like or directly competitive with Jeep four-wheel drive station-wagon vehicles.

Sales of Jeep's general utility vehicles (CJ5 and CJ7) increases significantly during 1978 compared with 1977. To meet this increased demand the Jeep Corporation converted a Brampton, Ontario plant to CJ body and final assembly during 1978 to supplement the fully-utilized production capacity at the Toledo, Ohio plant. When the Canadian plant began producing and exporting CJ models to the United States in September of 1978, production of the CJ models at the Toledo plant was reduced and the production of the other Jeep models at the Toledo plant was expanded to maintain full employment and production capacity.

Company sales of CJ models and the production of CJ models at both the Canadian and Toledo plants continued to increase from October, 1978 to March, 1979. In the second quarter of 1979, sales of CJ models, and consequently production at both the Canadian and Toledo plants, decreased in response to the oil crisis that increased gasoline prices and created uncertainty about the availability of fuel. Production cutbacks at both the Canadian and Toledo plants occurred during shutdown weeks in May, June and July of 1979. All Big Three automobile manufacturers experienced sales and production declines of four-wheel drive general utility vehicles during this period.

As production of CJ models resumed in August of 1979 at Toledo, the Jeep Corporation doubled the output of CJ models at the plant while reducing sharply the output of the other Jeep models. Concurrently, CJ production at the Canadian plant was reduced. This production increase at the Toledo plant indicates that the collapse of the domestic market for four-wheel drive general utility vehicles during the second quarter of 1979 was a response to the oil crisis and was the dominant cause of the production cutbacks of Jeep CJ models.

For workers assembling Jeep four-wheel drive pick-up trucks, all of the criteria have been met.

U.S. imports of four-wheel drive pick-up trucks increased both absolutely and relative to domestic production in 1978 compared to 1977 and in the first half of

1979 compared to the first half of 1978. Domestic retail market shares for four-wheel drive pick-up trucks increased for foreign-made models and decreased for domestic-made models.

Prior to the second quarter production cutbacks at the Toledo plant, production and sales of Jeep pick-up trucks decreased in the first quarter of 1979 compared with the first quarter of 1978. After the shutdowns the Jeep Corporation reduced sharply the output of four-wheel drive pick-up trucks at the Toledo, Ohio plant.

Conclusion

After careful review of the facts obtained in the investigation, I conclude that increases of imports of articles like or directly competitive with four-wheel drive pick-up trucks produced at the Toledo, Ohio facility of the Jeep Corporation contributed importantly to the decline in sales or production and to the total or partial separation of workers of that firm. In accordance with the provisions of the Act, I make the following certification:

All workers at the North Cove Boulevard plant and the Stickney Avenue plant in Toledo, Ohio of the Jeep Corporation engaged in employment related to the assembly of Jeep pick-up trucks (J-10 and J-20) who became totally or partially separated from employment on or after April 30, 1979 but before August 10, 1979 are eligible to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 28th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30979 Filed 10-4-79, 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5587]

MCR Fashions, Inc.; Notice of Negative Determination Regarding Application for Reconsideration

By application dated August 30, 1979, an official of the company where the workers are employed requested administrative reconsideration of the Department of Labor's Negative Determination Regarding Eligibility to Apply for Worker Adjustment Assistance in the case of workers and former workers producing ladies' coats at MCR Fashions, Inc., Hoboken, New Jersey. The determination was published in the Federal Register on August 14, 1979 (44 FR 47643).

Pursuant to 29 CFR 90.18(c), reconsideration may be granted under the following circumstances:

(1) if it appears on the basis of facts not previously considered that the determination complained of was erroneous;

(2) if it appears that the determination complained of was based on a mistake in the determination of facts previously considered; or

(3) if, in the opinion of the Certifying Officer, a misinterpretation of facts or of the law justifies reconsideration of the decision.

The petitioning company claims in its application for reconsideration that the unavailability of work for the spring season from coat manufacturers, including MCR Fashions' exclusive manufacturer, should be the reason why the industry as a whole should be used as a basis for meeting the "contributed importantly" test and not MCR Fashions' sole customer, a manufacturer.

The Department's review of the investigative case file revealed that workers at MCR Fashions were denied eligibility because the "contributed importantly" test of Section 222 of the Trade Act of 1974 was not met. The Department's survey revealed the MCR Fashions' sole manufacturer did not employ any foreign contractors or import any ladies' coats during the period under investigation. The survey further revealed that MCR Fashions' sole manufacturer had increased sales in 1978 compared to the like period in 1978. Further, the review indicated that MCR Fashions apparently did not produce for the spring season during the past two years since no one was employed for 10 to 12 weeks in early 1978 or 1979. Because a certification under the Trade Act of 1974 cannot cover separations which occurred more than one year prior to the date of a petition, the focus of the Department's investigation must be on separations which occurred within the coverable period.

With respect to the petitioning company's claim that industry data and not firm data be used to meet the criteria of Section 222 of the Trade Act of 1974, it should be noted that the language of the Trade Act covering adjustment assistance for workers specificaly addresses worker groups in "firms" or "subdivisions" of firms and not industries. One of the reasons is that even in import-impacted industries certain firms and their workers may not be harmed by import competition or may be predominantly harmed by factors not related to import competition. Further, regarding the unavailability of work the Department does not agree with the petitioning company's claim that the inability to obtain orders for coat production from other coat manufacturers can be considered as a basis for certification. Such potential losses cannot be considered as actual losses, i.e., sales and production declines, in meeting the Trade Act criteria necessary for a worker group certification.

Conclusion

After review of the application and the investigative file, I conclude that there has been no error or misinterpretation of the law which would justify reconsideration of the Department of Labor's prior decision. The application is, therefore, denied.

Signed at Washington, D.C., this 27th day of September 1979.

Harry J. Gilman,

Supervisory International Economist, Office of Foreign Economic Research.

[FR Doc. 79-30980 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5827]

The Panettieri Shirt Co., Inc., Bridgeport, Conn.; Certification Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance, each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on August 7, 1979 in response to a worker petition received on August 6, 1979 which was filed by the Amalgamated Clothing and Textile Workers' Union on behalf of workers and former workers producing ladies' man-tailored blouses and shirts at the Panettier Shirt Company, Incorporated, Bridgeport, Connecticut. The investigation revealed that the correct name of the company is the Panettieri Shirt Company, Incorporated. It is concluded that all of the requirements have been met.

Imports of women's, misses' and children's blouses and shirts increased both absolutely and relative to domestic production in 1978 as compared to 1977. The ratio of imports to domestic production was 67.1 percent in 1978.

Results of both a primary and a secondary survey conducted by the U.S. Department of Labor indicated that the Panettieri Company's sole customer, a manufacturer of women's shirts and blouses, decreased its contracts with the subject firm in 1978 as compared to 1977 as a result of a decrease in its own with retail customers whose purchases of imported shirts and blouses increased. Workers producing women's shirts and blouses at the subject firm's sole customer were certified eligible to apply for adjustment assistance in February 1979.

Conclusion

After careful review of the facts obtained in the investigation, I conclude that increases of imports of articles like or directly competitive with women's man-tailored shirts and blouses produced at the Panettieri Shirt Company, Incorporated, Bridgeport, Connecticut contributed importantly to the decline in sales or production and to the total or partial separation of workers of that firm. In accordance with the provisions of the Act, I make the following certification:

All workers of the Panettieri Shirt Company, Incorporated, Bridgeport, Connecticut who became totally or partially separated from employment on or after July 27, 1978 are eligible to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 27th day of September 1979.

Harry J. Gilman,

Supervisory International Economist, Office of Foreign Economic Research.

[FR Doc. 79-30981 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5790]

Regency Handbag Corp., Brooklyn, N.Y.; Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on July 30, 1979 in response to a worker petition received on July 10, 1979 which was filed by the Leather Goods, Plastics, Handbags and Novelty Workers Union on behalf of workers and former workers producing ladies' handbags at Regency Handbag Corporation, Brooklyn, New York. In the following determination, without regard to whether any of the other criteria have been met, the following criterion has not been met:

That increases of imports of articles like or directly competitive with articles produced by the firm or appropriate subdivision have contributed importantly to the separations, or threat thereof, and to the absolute decline in sales or production.

A survey was conducted by the Department of Labor of the manufacturers for whom Regency Handbag Corporation produced ladies' handbags. The survey revealed that none of the manufacturers purchased imported ladies' handbags or contracted out to foreign sources in 1977, 1978 or the first half of 1979. Most of the manufacturers indicated increased in-house production and increased sales of ladies' handbags. The only customer with decreased sales of ladies' handbags had purchased from Regency as part of a one-time deal.

Conclusion

After careful review, I determine that all workers of Regency Handbag Corporation, Brooklyn, New York are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 28th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30982 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5806 and 5954]

Reserve Mining Co., Babbitt and Silver Bay, Minn.; Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of investigations regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of section 222 of the Act must be met.

The investigations were initiated on July 31, 1979 and September 4, 1979 in response to worker petitions received on July 30, 1979 and September 16, 1979 which were filed by the United Steelworkers of America on behalf of workers and former workers mining taconite ore at the Babbitt Division of Reserve Mining Company, Babbitt, Minnesota (TA-W-5806) and on behalf of workers and former workers producing taconite pellets at the Silver Bay Division of Reserve Mining Corporation, Silver Bay, Minnesota (TA-W-5954). In the following determination, without regard to whether any of the other criteria have been met, the following criterion has not been met:

That increases of imports of articles like or directly competitive with articles produced by the firm or appropriate subdivision have contributed importantly to the separations, or threat thereof, and to the absolute decline in sales or production.

Taconite ore mined by the Babbitt Division is processed into taconite pellets by the Silver Bay Division. Sales and production of taconite pellets increased in the first seven months of 1978 compared with the same period in 1977. There was a strike at Reserve Mining which halted production from August through early December 1977. Employment at the Babbitt and Silver Bay Divisions increased in the first seven months of 1978 compared with the same period of 1977.

Production and employment declines in the first seven months of 1979 compared with the same period of 1978 can be attributed to the construction of a waste disposal system to meet environmental regulations. The Environmental Protection Agency has ordered Reserve Mining to complete the construction of an on-land waste disposal system by April 1980. In order to meet this deadline, temporary shutdowns are necessary.

Reserve Mining Company is jointly owned by two steel companies. These companies purchase all the taconite pellets produced by Reserve Mining.

Conclusion

After careful review, I determine that all workers of the Babbitt Division, Babbitt, Minnesota and the Silver Bay Division, Silver Bay, Minnesota of Reserve Mining Company are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 27th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30983 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5969]

Royalty Smokeless Coal Co.; Premier, W. Va., Engineering Department; Termination of Investigation

Pursuant to Section 221 of the Trade Act of 1974, an investigation was initiated on September 5, 1979 in response to worker petition received on August 14, 1979 which was filed by the United Mine Workers' of America on behalf of workers and former workers engaged in engineering work to develop the mines. The investigation revealed that workers of the Engineering Department are engaged in employment related to the cleaning of metallurgical coal.

The petitioning group of workers was certified as eligible to apply for adjustment assistance in a revised determination issued on September 20, 1979 (TA-W-5326). Since workers of the engineering Department of Royalty Smokeless Coal Company newly separated, totally or partially, from employment on or after April 19, 1978 (impact date) and before September 20, 1981 (expiration date of revised certification) are covered by an existing determination, a new investigation would serve no purpose. Consequently, the investigation has been terminated.

Signed at Washington, D.C. this 28th day of September 1979.

Marvin M. Fooks,

Director, Office of Trade Adjustment Assistance.

[FR Doc. 79-30984 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5971]

Royalty Smokeless Coal Co., Premier, W. Va., Rebuild Ship; Termination of Investigation

Pursuant to Section 221 of the Trade Act of 1974, an investigation was initiated on September 5, 1979 in response to worker petition received on July 20, 1979 which was filed by the United Mine Workers' of America on behalf of workers and former workers producing metallurgical coal at Royalty Smokeless Coal Company, Rebuild Shop, Premier, West Virginia. The investigation revealed that workers of the Rebuild Shop were engaged in employment related to the cleaning of metallurgical coal.

The petitioning group of workers was certified as eligible to apply for adjustment assistance in a revised determination issued on September 20, 1979 (TA-W-5326). Since workers of the Rebuild Shop of Royalty Smokeless Coal Company newly separated, totally or partially, from employment on or after April 19, 1978 (impact date) and before September 20, 1981 (expiration date of revised certification) are covered by an existing determination, a new investigation would serve no purpose. Consequently, the investigation has been terminated.

Signed at Washington, D.C. this 28th day of September 1979.

Marvin M. Fooks,

Director, Office of Trade Adjustment Assistance.

[FR Doc. 79-30985 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5947]

Stephen Ransom, Inc.; Port Newark, N.J.; Negative Determination Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issued a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on August 30, 1979, in response to a worker petition received on August 21, 1979, which was filed by the Industrial Union of Marine & Shipbuilding Workers of America on behalf of workers and former workers of Steven Ransom, Incorporated, Newark, New Jersey, engaged in conversion, repair, overhaul, and maintenance of marine vessels. The investigation revealed that the legal title of the firm is Stephen Ransom, Incorporated and that the proper location of the firm is Port Newark, New Jersey.

Stephen Ransom, Incorporated is engaged in providing the service of repairing ships.

Thus, workers of Stephen Ransom, Incorporated do not produce an article within the meaning of Section 222(3) of the Act. Therefore, they may be certified only if their separation was caused importantly by a reduced demand for their services from a parent firm, a firm otherwise related to Stephen Ransom, Incorporated by ownership, or a firm related by control. In any case, the reduction in demand for services must originate at a production facility whose workers independently meet the statutory criteria for certification and that reduction must directly relate to the product impacted by imports.

Stephen Ransom, Incorporated and its customers have no controlling interest in one another. The subject firm is not corporately affiliated with any other company. Neither the subject firm nor any company with which it shares common ownership produces and article.

All workers engaged in repairing ships at Stephen Ransom, Incorporated are employed by that firm. All personnel actions and payroll transactions are controlled by Stephen Ransom, Incorporated. All employee benefits are provided and maintained by Stephen Ransom, Incorporated. Workers are not, at any time, under employment or supervision by customers of Stephen Ransom, Incorporated. Thus, Stephen Ransom, Incorporated, and not any of its customers, must be considered to be the "workers' firm".

Conclusion

After careful review, I determine that all workers of Stephen Ransom, Incorporated, Port Newark, New Jersey are denied eligibility to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 28th day of September 1979.

C. Michael Aho,

Director, Office of Foreign Economic Research.

[FR Doc. 79-30986 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5858]

Trace Fork Coal Co.; Premier, W. Va., Tug River Mine; Termination of Investigation

Pursuant to Section 221 of the Trade Act of 1974, an investigation was initiated on August 13, 1979 in response to a worker petition received on July 20, 1979 which was filed by the United Mine Workers of America on behalf of workers and former workers engaged in the mining of coal at Trace Fork Coal Company, Tug River Mine, McDowell County, West Virginia. The investigation revealed that the Tug River Mine of Trace Fork Coal Company, Premier, West Virginia produces metallurgical coal.

The Tug River Mine of Trace Fork Coal Company, acquired by Trace Fork Coal Company on December 31, 1978 when Tug River Coal Company was merged into Trace Fork, began coal production in January, 1979. Tug River Coal Company, an affiliate of Trace Fork created in 1977, never produced coal. Oweing to the brevity of productive operations at the Tug River Mine, it is impossible to determine trends of sales and production or to statistically measure the impact of imports of coke on business conditions at the Tug River Mine. Consequently, the investigation has been terminate.

Signed at Washington, D.C. this 27th day of September 1979.

Marvin M. Fooks,

Director, Office of Trade Adjustment Assistance.

[FR Doc. 79-30987 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5872]

Trace Fork Coal Co., Premier, W. Va., Premier Office; Termination of Investigation

Pursuant to Section 221 of the Trade Act of 1974, an investigation was initiated on August 17, 1979 in response to worker petition received on August 4, 1979 which was filed by the United Mine Workers' of America on behalf of workers and former workers in the Premier Office of Trace Fork Coal Company, Premier, West Virginia.

The petitioning group of workers was certified as eligible to apply for adjustment assistance in a revised determination issued on September 20, 1979 (TA-W-5330-5333). Since workers of the Premier Office of Trace Fork Coal Company newly separated, totally or partially, from employment on or after April 19, 1978 (impact date) and before September 20, 1981 (expiration date of revised certification) are covered by an existing determination, a new investigation would serve no purpose. Consequently, the investigation has been terminated.

Signed at Washington, D.C., this 28th day of September 1979.

Marvin M. Fooks,

Director, Office of Trade Adjustment Assistance.

[FR Doc. 79-30988 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5970]

Trace Fork Coal Co.; Premier, W. Va., Trace Fork Mine No. 12, Termination of Investigation

Pursuant to Section 221 of the Trade Act of 1974, an investigation was initiated on September 5, 1979 in response to worker petition received on July 20, 1979 which was filed by the United Mine Workers' of America on behalf of workers and former workers producing metallurgical coal at Trace Fork Coal Company, Mine #12, Premier, West Virginia. The investigation revealed that the correct title is Trace Fork Mine #12 of Trace Fork Coal Company.

The petitioning group of workers was certified as eligible to apply for adjustment assistance in a revised determination issued on September 20, 1979 (TA-W-5330-5333). Since workers of the Trace Fork Mine #12 of Trace Fork Coal Company newly separated, totally or partially, from employment on or after April 19, 1978 (impact date) and before September 20, 1981 (expiration date of revised certification) are covered by an existing determination, a new investigation would serve no purpose. Consequently, the investigation has been terminated.

Signed at Washington, D.C. this 28th day of September 1979.

Marvin M. Fooks,

Director, Office of Trade Adjustment Assistance.

[FR Doc. 79-30989 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5645]

Transamerica Delaval, Turbine Division; Trenton, N.J.; Determinations Regarding Eligibility To Apply for Worker Adjustment Assistance.

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance, each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on June 22, 1979 in response to a worker petition received on June 18, 1979 which was filed by the United Steelworkers of America on behalf of workers and former workers producing turbines and IMO pumps at the Trenton, New Jersey plant of Transamerica Delaval. The investigation revealed that the petition was intended to apply only for workers employed in the Turbine Division and not the IMO Pump Division. In the following determination, without regard to whether any of the other criteria have been met for workers producing turbines and pumps, the following criterion has not been met:

That increases of imports of articles like or directly competitive with articles produced by the firm or appropriate subdivision have contributed importantly to the separations, or threat thereof, and to the absolute decline in sales or production.

Transamerica Delaval produces steam turbines and pumps to customer specification from orders procured by competitive bid. The Department obtained information on both the turbine contracts and the pump contracts which Delaval lost during the period January 1977-June 1979. The information on turbine contracts revealed that the major contract which Delaval lost during this time period was to a foreign manufacturer of slow speed diesel turbines. At the present time, there are no domestic manufacturers with the capacity to produce slow speed diesel turbines.

The data received on the pump contracts which Delaval lost revealed that Transamerica Delaval was not the lowest domestic bidder on those contracts that were awarded to foreign manufacturers.

For workers producting compressors, all of the criteria have been met.

U.S. imports of air and gas compressors increased absolutely and relative to domestic production from 1977 to 1978 and increased absolutely in the first quarter of 1979 compared to the same period in 1978.

Transamerica Delaval custom produces compressors on the basis of bids procured. The Department obtained data on contracts for compressors lost by Delaval in the last three years. The data revealed that Transamerica Delaval lost major contracts for which it was the lowest domestic bidder to foreign manufacturers in 1977, 1978 and 1979.

Production at Delaval is recorded in terms of bookings, which represents contracts awarded to the subject firm. Actual production takes place between the time that the order is booked and the time at which the finished product is shipped. The compressor contracts on which Delaval was lowest domestic bidder but were awarded to foreign manufacturers for production in 1979 constituted an amount equal to a substantial proportion of Delaval's compressor production in 1977 and 1978.

The petitioners allege that imports from Delaval's facilities in Canada and the Netherlands adversely affected production and employment at the Trenton facility. However, the Canadian plant produces different sizes of compressors than the Trenton plant. Production is allocated between Canada and Trenton on the basis of size of compressor, plant capacity and available capital equipment. Therefore, the two facilities operate in a complementary rather than competitive manner.

Delaval allocated an order to its Netherlands facility in 1978. However, this represented excess production from Trenton at a time when the Trenton facility of the Turbine Division was working at full capacity.

Conclusion

After careful review of the facts obtained in the investigation, I conclude that increases of imports of articles like or directly competitive with compressors produced by the Trenton, New Jersey plant of the Turbine Division of Transamerica Delaval, contributed importantly to the decline in sales or production and to the total or partial separation of workers producing compressors at that firm. In accordance with the provisions of the Act, I make the following certification:

All workers of the Trenton, New Jersey plant of the Turbine Division of Transamerica Delaval, engaged in employment related to the production of compressors, who became totally or partially separated from employment on or after January 1, 1979 and before January 1, 1980 are eligible to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974. All workers who become totally or partially separated from employment on or after January 1, 1980 are denied eligibility to apply for adjustment assistance.

Signed at Washington, D.C. this 27th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning

[FR Doc. 79-30990 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5716]

U.S. Steel Corp.; U.S. Steel Products Division; Camden (Delair), N.J.; Negative Determination Regarding Application for Reconsideration

By an application dated September 18, 1979, the United Steelworkers of America (USWA) requested administrative reconsideration of the Department of Labor's Negative Determination Regarding Eligibility to Apply for Worker Adjustment Assistance in the case of workers and former workers producing steel pails and drums at U.S. Steel Corporation's Camden (Delair), New Jersey plant. The determination was published in the Federal Register on August 31, 1979 (44 FR 51371).

Pursuant to 29 CFR 90.18(c), reconsideration may be granted under the following circumstances:

(1) if it appears on the basis of facts not previously considered that the determination complained of was erroneous;

(2) if it appears that the determination complained of was based on mistake in the determination of facts previously considered; or

(3) if, in the opinion of the Certifying Officer, a misinterpretation of facts or of the law justifies reconsideration of the determination.

The petitioning union claims in its application for reconsideration that the Camden (Delair), New Jersey, plant of U.S. Steel is part of an integrated production process with U.S. Steel Corporation's steel plants which produce steel sheet and strip. The petitioning union further claims that increased imports of steel sheet and strip which are the principal components of steel pails and drums are responsible for the workers' separations at the Camden, New Jersey, plant.

The Department's review revealed that workers at the Camden (Delair), New Jersey, plant did not meet the "contributed importantly" test of Section 222 of the Trade Act of 1974. The Department's survey of Camden's customers revealed that imports of steel pails and drums played a de minimis role in the purchasing patterns of those customers.

The Department found no integration in the production process of the Camden (Delair), New Jersey, plant of U.S. Steel. The Camden plant is a producer of steel pails and drums whereas the supplying U.S. Steel plants produce steel sheet and strip—components of steel pails and drums. According to a high company official, none of Camden's output is used in the production process at other U.S. Steel plants producing steel sheet and strip. Further, while Camden received raw materials from other U.S. Steel plants, the certification of certain U.S. Steel suppliers of steel sheet and strip was not based on operations at Camden. The certification of certain U.S. Steel workers producing steel sheet and strip, therefore, has no bearing on the certifiability of Camden workers.

The Camden, New Jersey, plant did not produce steel sheet and strip whose importation the petitioners identify as contributing to their separations. Therefore, imports of steel pails and drums must be considered in determining import injury to workers producing steel pails and drums. The Department's investigation revealed that imports of steel pails and drums like or directly competitive with those produced by the workers of U.S. Steel's Camden, New Jersey, plant are negligible. Components of steel pails and drums, such as steel sheet and strip, cannot be considered "like or directly competitive" with the finished articles. See *United Shoe Workers of America* vs. *Bedell* 506 F. 2d., (1974).

Conclusion

After review of the application and the investigative file, I conclude that there has been no error or misinterpretation of fact or misinterpretation of the law which would justify reconsideration of the Department of Labor's prior decision. The application is, therefore, denied.

Signed at Washington, D.C., This 28th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30991 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5758]

U.S. Steel Corp., Pittsburg Works, Pittsburg, Calif.; Determinations Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 U.S.C. 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on July 17, 1979 in response to a worker petition received on July 12, 1979 which was filed by the United Steelworkers of America on behalf of workers and former workers of the Pittsburg Works of the U.S. Steel Corporation in Pittsburg, California engaged in employment related to the production of carbon steel wire, rod, wire products, pipe and tubing. The investigation revealed that the plant also produces hot rolled sheet, cold rolled sheet, galvanized sheets, tin plate, and nails. In the following determination, without regard to whether any of the other criteria have been met for workers producing cold rolled carbon steel sheet, carbon steel wire rod, tin plate, hot rolled carbon steel sheet, nails, carbon steel pipe and tubing, and carbon steel wire and wire products, the following criterion has not been met:

That increases of imports of articles like or directly competitive with articles produced by the firm or appropriate subdivision have contributed importantly to the separations, or threat thereof, and to the absolute decline in sales or production.

U.S. imports of cold rolled carbon steel sheet, U.S. imports of tin plate and tin free steel and U.S. imports of carbon steel wire rod declined both absolutely and relative to domestic shipments in 1978 compared with 1977 and in the first six months of 1979 compared with the first six months of 1978.

With respect to hot rolled carbon steel sheet produced at the Pittsburg Works, a survey of major customers indicated that although the survey participants' overall demand for U.S. Steel's carbon steel sheet declined in 1978 compared with 1977, these customers' overall reliance upon imported carbon steel sheet declined over the same period and purchases from other domestic sources increased.

Similarly, customers which decreased purchases of hot rolled carbon steel sheet from the Pittsburg Works in the first half of 1979 compared to the first half of 1978 also decreased their purchases from foreign sources both absolutely and relative to total purchases.

Plant sales and production of nails at the Pittsburg Works increased in 1978 compared to 1977 and increased in the first quarter of 1979 compared to the first quarter of 1978. A survey of major customers which purchase nails produced at the Pittsburg Works indicated that customers which decreased purchases from the subject plant in the first seven months of 1979 compared to the like 1978 period also decreased their purchases of imported nails both absolutely and relative to total purchases. These customers increased their purchases from other domestic sources during this time period.

Workers producing carbon steel pipe and tubing at the Pittsburg Works of U.S. Steel were previously certified eligible to apply for adjustment assistance on August 26, 1977 (TA-W-1446). That certification expired on August 26, 1979, two years from its date of issuance.

Sales of carbon steel pipe and tubing by the Pittsburg Works increased in the first and second quarters of 1979 compared to both the previous quarter and the same quarter previous year.

Furthermore, a Department survey of major customers of the Pittsburg Works for pipe and tubing revealed that customers which decreased purchases from the subject plant in the first seven months of 1979 compared with the first seven months of 1978 also decreased their purchases of imports both absolutely and relative to total purchases. These customers increased their purchases from domestic sources during the same time period.

Sales of wire and wire products by the Pittsburg Works of U.S. Steel Corporation increased from 1977 to 1978 and in the first six months of 1979 compared with the first six months of 1978. Sales increased in each quarter from the second quarter of 1978 through second quarter of 1979 both compared with the previous quarter and the same quarter previous year.

Additionally, a Department survey of customers of the Pittsburg Works for wire products revealed that none of the customers surveyed purchased any imported wire in 1977, 1978 or the first seventh months of 1979.

For workers producing galvanized steel sheet, all of the criteria have been met.

U.S. imports of galvanized steel sheet increased both absolutely and relative to domestic shipments in 1978 compared to 1977 and declined both absolutely and relative to domestic shipments in the first half of 1979 compared to the like period 1978.

The Department conducted a survey of major customers which purchase galvanize steel sheet produced at the Pittsburg Works of U.S. Steel. The survey indicated that customers representing a significant proportion of the decline in sales of galvanized steel sheet by the Pittsburg Works from 1977 to 1978 increased their purchases of imported galvanized steel sheet during the same period.

Conclusion

After careful review of the facts obtained in the investigation, I conclude that increases of imports of articles like or directly competitive with galvanized steel sheet produced by the Pittsburg Works of the U.S. Steel Corporation in Pittsburg, California contributed importantly to the decline in sales or production and to the total or partial separation of workers producing galvanized steel sheet at that plant. In accordance with the provisions of the Act, I make the following certification:

All workers of the Pittsburg Works of the U.S. Steel Corporation, Pittsburg, California engaged in employment related to the production of galvanized steel sheet who became totally or partially separated from employment on or after June 30, 1978 and before January 1, 1979 are eligible to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974. All workers who became totally or partially separated from employment on or after January 1, 1979 are denied eligibility to apply for adjustment assistance.

Signed at Washington, D.C. this 27th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30992 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

[TA-W-5837]

Victor Wraps, Inc.; Certification Regarding Eligibility To Apply for Worker Adjustment Assistance

In accordance with Section 223 of the Trade Act of 1974 (19 USC 2273) the Department of Labor herein presents the results of an investigation regarding certification of eligibility to apply for worker adjustment assistance.

In order to make an affirmative determination and issue a certification of eligibility to apply for adjustment assistance, each of the group eligibility requirements of Section 222 of the Act must be met.

The investigation was initiated on August 8, 1979 in response to a worker petition received on August 6, 1979 which was filed by the International Ladies Garment Workers Union on behalf of workers and former workers producing women's outerwear at Victor Wraps, Incorporated, Camden, New Jersey. The investigation revealed that the women's outerwear produced by the company consists of coats, blazers, capes and suit ensembles. It is concluded that all of the requirements have been met.

Imports of women's, misses and children's coats and jackets (including capes) increased both absolutely and relatively to domestic production in 1978 as compared to 1977.

Imports of women's, misses' and children's suits increased both absolutely and relative to domestic production in 1978 as compared to 1977.

In a survey conducted by the U.S. Department of Commerce, customers accounting for a significant proportion of Victor Wraps' sales declines indicated that they had decreased purchases from Victor Wraps, Incorporated and had increased purchases of imported women's outwear.

The Department of Commerce on September 11, 1979 certified Victor Wraps, Incorporated eligible to apply for firm adjustment assistance (Project No. F-NJ-0353).

Conclusion

After careful review of the facts obtained in the investigation, I conclude that increases of imports of articles like or directly competitive with women's outerwear, consisting of coats, capes, blazers and suit ensembles, produced at Victor Wraps, Incorporated, Camden, New Jersey contributed importantly to the decline in sales or production and to the total or partial separation of workers of that firm. In accordance with the provisions of the Act, I make the following certification:

All workers of Victor Wraps, Incorporated, Camden, New Jersey who became totally or partially separated from employment on or after July 26, 1978 are eligible to apply for adjustment assistance under Title II, Chapter 2 of the Trade Act of 1974.

Signed at Washington, D.C. this 28th day of September 1979.

James F. Taylor,

Director, Office of Management, Administration and Planning.

[FR Doc. 79-30993 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-28-M

Office of the Secretary

Workplace Privacy; Notice of Hearings

Notice is hereby given that the Department of Labor is seeking to obtain information concerning policies and practices relating to the protection of workplace privacy in the private sector. The principal vehicle for undertaking this study will be a series of public hearings to be held throughout the country during the coming winter. These hearings will consider the extent to which the recommendations of the Privacy Protection Study Commission have been followed; identify the practical problems that have arisen in the implementation of these recommendations, as well as possible solutions for these difficulties; and consider whether the Commission's recommendations are fully adequate or whether further refinement of the principles set forth by the Commission would be useful. The hearings will examine a broad range of employer practices and policies relating to workplace privacy, including the techniques used to gather information about workers and applicants, the maintenance of such information by the employer, and the internal and external uses of such information.

In 1977, the Privacy Protection Study Commission issued its final report. The Commission was created by the Privacy Act of 1974 to examine individual privacy rights in many institutional contexts. One of the major areas of inquiry was workplace privacy in the private sector. This examination led to a series of wide-ranging recommendations, contained in the Commission's report. Chapter 6 of the report deals specifically with workplace privacy.[1]

Following the issuance of the Commission's final report, the Administration undertook an exhaustive analysis of its recommendations. Numerous cabinet departments and agencies participated in this effort. These efforts were coordinated by the National Telecommunications and Information Administration (NTIA) of the Department of Commerce. On April 2, 1979, President Carter transmitted a message to Congress which set forth certain proposals for the protection of individual privacy in various areas.

With respect to privacy in employment relationships, President Carter's message urged continuing progress toward implementing the policies set forth in the Commission's report. He instructed the Secretary of Labor to work with employer and employee groups in this implementation.

In order to carry out this Presidential directive, the Department of Labor is announcing a series of hearings focusing on the workplace privacy practices of employers, including those relating to the collection, maintenance, and use of information and records on employees and applicants, as well as employee access to such records. NTIA will cooperate in these hearings. These hearings will have four principal objectives: 1) to consider the extent to which private employers have formulated and implemented policies and practices which are consistent with the principles set forth by the Privacy Commission; 2) to identify the practical problems which have arisen in implementing the various aspects of the Privacy Commission's recommendations, and to consider whether and how these problems can best be remedied; 3) to develop information that will assist employer and employee groups in improving practices related to workplace privacy; and 4) to consider steps that can be taken to assure workplace privacy in the future.

More than two years have passed since the Commission issued its report. Although some efforts already have been made to assess the progress which has been made, it is important at this time to focus attention more sharply on the extent of this progress and to establish clearly what remains to be done in this area that so vitally affects millions of American workers and their families.

The Department of Labor invites all interested parties to participate in, and otherwise contribute to, these hearings. The Department seeks information from individual employers and employees as well as employer and employee groups which have had experience relating to workplace privacy policies and practices. The Department is interested in learning of the experience of medium and small businesses as they pertain to the recommendations of the Privacy Protection Study Commission. It will also welcome contributions from individual citizens, public interest groups, public and private organizations, persons from the academic community, and companies which provide services to employers in such areas as systems management, computer technology, and personnel assessment.

The specific dates and locations of the hearings have not as yet been determined. However, the Department is planning to hold hearings at several locations throughout the country during the coming winter.

Any individual, organization, association, or other group desiring to present oral testimony to the Departmental task force and to participate at the hearings should notify the Department prior to November 16, 1979. Requests to testify should be addressed to:

Seth D. Zinman, Associate Solicitor for Legislation and Legal Counsel, U.S. Department of Labor, Room N-2428, 200 Constitution Avenue, NW., Washington, D.C. 20210. Phone No. (202) 523-8201.

Following receipt of materials and requests to testify, the Department will contact those individuals and groups who respond to this Notice and devise a hearing schedule and identify specific hearing locations. The schedule and sites will be publicly announced in the Federal Register and other publications at the earliest possible date.

Because of the broad range of issues arising in the area of workplace privacy, it would be extremely helpful if potential participants would identify the specific topics they wish to address and, if possible, submit a written statement no later than two weeks in advance of their oral presentation.

In addition, the Department is interested in securing copies of existing policy statements and procedural guidelines relating to the collection, maintenance, and use of employment and employment-related information

[1] Copies of the report entitled, "Personal Privacy in an Information Society," can be obtained from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402 (Stock No. 052-003-00395-3). The Commission also published an Appendix 3, entitled "Employment Records", to its report. This appendix provided more extensive background information relating to the Commission's recommendations. Copies of the appendix can also be obtained from the Superintendent of Documents (Stock No. 052-003-00423-2).

and records. Employers, employee unions, and other organizations having such materials are invited to submit two copies to Mr. Zinman at the above address prior to October 31, 1979.

To assist potential participants in preparing their presentations, the Department anticipates that the following issues will be covered at the hearings:

1. What employer policies and procedures have been established with respect to:

a. The use of "pretext interviews" and other intrusive techniques for gathering information about job applicants and employees.

b. The use of polygraph or other "truth-verification" devices to gather information from applicants and employees.

c. The use of psychological tests, particularly measures of personality and attitudes, for job applicants and employees.

d. The use of electronic surveillance devices.

e. Assuring that information gathered about applicants and workers is relevant to decisions being made, that it is accurate and current, and that it does not serve to stigmatize and individual unfairly.

f. Informing employees and applicants of the commencement of employment-related investigations.

g. The institution of safeguards to assure that only investigative firms are used which employ appropriate methods to gather information about employees and job applicants.

h. Informing employees and applicants of the types of information about them gathered and maintained, the investigative sources and techniques utilized and the types of sources to be contacted in gathering this information, the use of this information within the organization, and the organization's disclosure practices.

i. Permitting individual employees, former employees, and applicants to see, copy, correct, or amend records maintained on them.

j. The right of access to employment-related medical records and employee insurance records, and the limitations imposed on the use of such records in employment decisions.

k. Policies on the use of arrest and conviction records in making employment decisions.

l. Internal protection of sensitive records to assure that their availability within the firm is limited to those with a legitimate need for the information.

m. Disclosure of personal employment records, including those relating to work performance, to third parties; and requirements governing notice or written permission for such disclosures.

2. Where employers have adopted components of a fair information practices policy, have sufficient steps been taken to insure that the policy has been carried out, including:

a. The conduct of periodic evaluations of personnel record-keeping practices; and

b. The designation of an executive-level person to be responsible for maintaining privacy safeguards in employment record-keeping practices?

3. Where fair information practices have been established, are employees being adequately informed that there is a policy and of any rights which have been afforded them?

4. Where employees have been afforded an opportunity to inspect and/or copy records maintained on them, how frequently have such rights been exercised?

5. What problems have been encountered in adopting or implementing the recommendations of the Privacy Protection Study Commission? What steps can be taken to remedy these problems?

6. Have the costs and administrative work needed to carry out a strong privacy policy proven to be manageable?

7. How have employers accommodated privacy policy with other corporate objectives? What, if any, corporate objectives have, in practice, proven to be inconsistent with a privacy policy?

8. Have employees been surveyed on their privacy concerns or involved in the development of such a policy?

9. Have the practices recommended by the Privacy Protection Study Commission been beneficial to employees?

10. Are there any aspects of workplace privacy which the Privacy Protection Study Commission failed to address, or do any of its recommendations need further refinement or expansion?

11. Are there any other aspects of workplace privacy that you believe should be considered at these hearings?

12. In what ways can the federal government assist private employers in achieving the objectives of workplace privacy?

Further information on these hearings can be obtained from Mr. Zinman at the above address or from:

Robert A. Shapiro, Office of the Solicitor, U.S. Department of Labor, Room N-2428, 200 Constitution Avenue, NW., Washington, D.C. 20210. Phone: (202) 523-8176.

Signed at Washington, D.C., this 2nd day of October, 1979.

Ray Marshall,

Secretary of Labor.

[FR Doc. 79-31043 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-23-M

Pension and Welfare Benefit Programs

[Prohibited Transaction Exemption 79-54; Application No. D-1374]

Employee Benefit Plans; Exemption From the Prohibitions for Certain Transactions Involving Great Lakes Mortgage Corp. Employees' Profit Sharing Plan and Trust

AGENCY: Department of Labor.

ACTION: Grant of individual exemption.

SUMMARY: This exemption permits the negotiation and execution by the Trustees of the Great Lakes Mortgage Corporation Employees' Profit Sharing Plan and Trust (the Trust) of an agreement (the Agreement) with The Lomas & Nettleton Company (L & N) to sell all of the Great Lakes Mortgage Corporation (GLMC) stock held by the Trust to L & N. The exemption will also permit the consummation by the Trustees and L & N of those provisions of the Agreement which provide for the release and indemnification of GLMC and L & N by the Trust, for the holdback provisions and for L & N's rights of offset and reduction against the holdback.

FOR FURTHER INFORMATION CONTACT: Mr. Robert N. Sandler of the Office of Fiduciary Standards, Pension and Welfare Benefit Programs, Room C-4526, U.S. Department of Labor, 200 Constitution Avenue, NW., Washington, D.C. 20216, (202) 523-8883. (This is not a toll-free number).

SUPPLEMENTARY INFORMATION: On July 3, 1979 notice was published in the Federal Register (44 FR 39051) of the pendency before the Department of Labor (the Department) of a proposal to grant an exemption from the restrictions of sections 406(a) and 406(b)(1) and (b)(2) of the Employee Retirement Income Security Act of 1974 (the Act) and from the taxes imposed by sections 4975(a) and (b) of the Internal Revenue Code of 1954 (the Code) by reason of sections 4975(c)(1)(A) through (E) of the Code, for transactions described in an application filed on behalf of the Trust. The notice set forth a summary of facts and representations contained in the application for exemption and referred interested persons to the application for a complete statement of the facts and representations. The application has been available for public inspection at the Department in Washington, D.C. The notice also invited interested persons to submit comments on the requested exemption to the Department. In addition, the notice stated that any interested person might submit a written request that a public hearing be held relating to this exemption. Several comments and requests for a hering were received by the Department. Notice of a public hearing was published in the Federal Register on August 10, 1979 (44 FR 47185). The hearing was held at the Department in Washington, D.C., on September 10, 1979, at which hearing persons presented testimony explaining their views with respect to the proposed exemption.

Effective December 31, 1978, section 102 of Reorganization Plan No. 4 of 1978 (43 FR 47713, October 17, 1978) transferred the authority of the Secretary of the Treasury to issue exemptions of the type requested to the Secretary of Labor. Therefore, this exemption is issued solely by the Department.

Discussion of Comments and Testimony Received at Public Hearing

Following publication of the proposed exemption, the Department received eight comments. Six of the comments were from participants in the Trust and/or employees of GLMC. Four of the comments supported the proposed exemption and the other two comments objected to the proposed exemption. One comment was from the Trustees of GLMC, and the other comment was from the representative of L & N, both of which comments supported the proposed exemption but suggested that several amendments be made.

Both of the objecting comments expressed general concerns that were not specificaly related to the merits of the proposed exemption. Additionally, one of the commentators stated that the holdback from the purchase price of $2 million for GLMC contingent liabilities was not in the interests of Trust participants. This matter was also addressed at the public hearing and is further discussed below.

The commentators representing the Trust and L & N request that L & N be treated as a party in interest and disqualified person with respect to the Trust for purposes of the exemption. Therefore, the Department has determined that the exemption shall include the transactions between the Trust and L & N that might be prohibited under section 406 of the Act and section 4975(c) of the Code if L & N is deemed a party in interest or disqualified person with respect to the Trust. These transactions include the consummation of the Agreement by L & N (discussed below), the release and indemnification of L & N by the Trust, the holdback provision and L & N's rights of offset and reduction against the holdback. All of these transactions were described in the Proposed Exemption under the heading "Summary of Facts and Representations".

The commentators representing the Trust and L & N also request that the exemption be made applicable to the consummation of the Agreement as well as to its negotiation and execution. They feel this addition is necessary to avoid any misunderstanding as to the nature and scope of the exemption. The Department has acceded to this request.

The same commentators also requested and the Department has determined that the exemption should reflect Amendment Nos. 4 and 5 to the Trust, regarding the termination of the employment of GLMC employees upon the liquidation and dissolution or merger of GLMC. The Trustees state that L & N has advised GLMC that it will not adopt the Trust and that, promptly after the transfer of the GLMC stock, GLMC will be dissolved and liquidated or merged. The Trust provides that the employment of each GLMC employee, if not previously terminated, will be considered for all purposes as terminated at the time of dissolution or merger and in any event not later than 10 days following the transfer of stock and that the Plan under the Trust will terminate on the dissolution or merger of GLMC.

Finally, the commentators representing the Trust and L & N request and the Department has determined that the exemption should reflect Amendment Nos. 2 and 3 to the Agreement. These amendments extend the closing date for the Agreement from June 30, 1979 to September 28, 1979, or such other date as may be agreed upon between the Trust and L & N. Furthermore, in the Proposed Exemption it was stated (in item 6 of the Summary of Facts and Representations) that there would be certain plus or minus adjustments to the $2,000,000 holdback which would be made within 45 days after the closing date. Pursuant to the Amendments to the Agreement, these adjustments will be made on or prior to the closing date. Amendment No. 2 also provides that the final payment date be the 170th day after the closing date or the 10th day after the receipt of a favorable Internal Revenue Service determination letter, whichever is later.

The hearing was held at the Department in Washington on September 10, 1979. Testimony was received from four persons, all of whom spoke in favor of the proposed exemption. The concerns of the objecting commentators were addressed at length. Testimony was given regarding the negotiation of the holdback provision. It was also stated that the Department is in possession of copies of the Agreement of which the holdback provision is a part. It was further stated that holdback provisions are customary in transactions of this type and that the $2 million holdback and indemnification and offset provision in this case provide better terms for the Trust than parties in the position of the Trust ordinarily obtain in similar transactions.

After consideration of the comments received and the testimony presented at the hearing, the Department has decided to grant the requested exemption with the changes discussed above. These changes are not of a nature that would substantively affect the merits of the proposed transaction.

General Information

The attention of interested persons is directed to the following:

(1) The fact that a transaction is the subject of ane exemption granted under section 408(a) of the Act and section 4975(c)(2) of the Code does not relieve a fiduciary or other party in interest or disqualified person with respect to a plan to which the exemption is applicable from certain other provisions of the Act and the Code.

These provisions include any prohibited transactions provisions to which the exemption does not apply and the general fiduciary responsibility provisions of section 404 of the Act, which among other things require a fiduciary to discharge his or her duties respecting the plan solely in the interests of the participants and beneficiaries of the plan and in a prudent fashion in accordance with section 404(a)(1)(B) of the Act; nor does the fact that the transaction is the subject of an exemption affect the requirement of section 401(a) of the Code that a plan must operate for the exclusive benefit of the employees of the employer maintaining the plan and their beneficiaries.

(2) This exemption does not extend to transactions prohibited under section 406(b)(3) of the Act and section 4975(c)(1)(F) of the Code.

(3) This exemption is supplemental to, and not in derogation of, any other provisions of the Act and the Code, including statutory or administrative exemptions and transitional rules. Furthermore, the fact that a transaction

is subject to an administrative or statutory exemption or transitional rule is not dispositive of whether the transaction is, in fact, a prohibited transaction.

Exemption

In accordance with section 408(a) of the Act and section 4975(c)(2) of the Code and the procedures set forth in ERISA Procedure 75-1 (40 FR 18471, April 28, 1975), and based upon the entire record, the Department makes the following determinations:

(a) The exemption is administratively feasible;

(b) It is in the interests of the Trust and of its participants and beneficiaries; and

(c) It is protective of the rights of the participants and beneficiaries of the Trust.

Accordingly, the restrictions of section 408(a), 406(b)(1) and (b)(2) of the Act and the taxes imposed by section 4975(c)(1)(A) through (E) of the Code shall not apply to the negotiations and execution of the Agreement by the Trustees. The exemption will also permit the consummation by the Trustees and L & N of those provisions of the Agreement which provide for the release and indemnification of GLMC and L & N, for the holdback provision, and for L & N's rights of offset and reduction against the holdback.

The availability of this exemption is subject to the express condition that the material facts and representations contained in the application are true and complete, and that the application accurately describes all material terms of the transaction to be consummated pursuant to this exemption.

Signed at Washington, D.C., this 26th day of September, 1979.

Ian D. Lanoff,

Administrator for Pension and Welfare Benefit Programs, Labor-Management Services Administration, Department of Labor.

[FR Doc. 79-30947 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-29-M

NATIONAL FOUNDATION ON THE ARTS AND THE HUMANITIES

Federal-State Partnership Panel (State Programs Section); Meeting

Pursuant to Section 10 (a) (2) of the Federal Advisory Committee Act (Public Law 92-463), notice is hereby given that a meeting of the Federal-State Partnership Panel (State Programs Section) will be held on October 31, 1979, from 9:00 a.m.-5:30 p.m., and on November 1, 1979, from 9:00 a.m.-5:30 p.m., in the Columbia Plaza Office Building, Room 1426, 2401 E St., N.W., Washington, D.C.

This meeting will be open to the public on a space available basis. The topic for discussion will be Policy and Planning.

Further information with reference to this meeting can be obtained from Mr. John H. Clark, Advisory Committee Management Officer, National Endowment for the Arts, Washington, D.C. 20506, or call (202) 634-6070.

John H. Clark,

Director, Office of Council and Panel Operations, National Endowment for the Arts.

[FR Doc. 79-31011 Filed 10-4-79; 8:45 am]

BILLING CODE 7537-01-M

Federal-State Partnership Panel; Meeting

Pursuant to Section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92-463), notice is hereby given that a meeting of the Federal-State Partnership Advisory Panel to the National Council on the Arts will be held on October 31, 1979, from 9:00 a.m.—5:30 p.m.; and on November 1, 1979 from 9:00 a.m.—5:30 p.m. in room 1340 of the Columbia Plaza Office Building, 2401 E St., NW., Washington, D.C. 20506.

This meeting will be open to the public on a space available basis. The topic for discussion will be policy and the five year plan.

Further information with reference to this meeting can be obtained from Mr. John H. Clark, Advisory Committee Management Officer, National Endowment for the Arts, Washington, D.C. 20506, or call (202) 634-6070.

John H. Clark,

Director, Office of Council and Panel Operations, National Endowment for the Arts.

[FR Doc. 79-31012 Filed 10-4-79; 8:45 am]

BILLING CODE 7537-01-M

NUCLEAR REGULATORY COMMISSION

[Docket No. PRM-40-22]

Defense Security Assistance Agency

Notice is hereby given that Lieutenant General Ernest Graves, Director, Defense Security Assistance Agency, by petition dated August 3, 1979, has requested that the Nuclear Regulatory Commission (NRC) add a new section 40.23 to the Commission's 10 CFR Part 40, Domestic Licensing of Source Material (currently effective as section 110.23 in 10 CFR Part 110, "Export and Import of Nuclear Facilities and Materials") to provide:

(g) A general license is hereby issued authorizing the Department of Defense to export to any authorized country pursuant to the Arms Export Control Act or the foreign Assistance Act of 1961 depleted uranium in munitions penetrators, provided that each such export is approved by the department of State pursuant to either Act.

The petitioner states that the Department of defense is now seeking statutory authority to sell or grant depleted uranium munitions on a government-to-government basis by amending the Arms Export Control Act and Foreign Assistance Act. These acts currently do not include depleted uranium penetrators within the definition of a "defense article" which the Department of Defense is authorized to sell to foreign governments. The Department of Defense believes that statutory amendments to the Arms Export and Control Act and the Foreign Assistance Act, which would in effect include depleted uranium penetrators within the definition of a "defense article", are about to be adopted by the Congress in H.R. 3173, 96th Congress, the International Security Assistance Act of 1979. In anticipation of this legislation, which will in effect authorize the Department of Defense to sell depleted uranium munitions on a government-to-government basis, petition is being made at this time for a general license for the Department of Defense to export depleted uranium contained in defense articles granted or sold on a government-to-government basis under the authority of the Foreign Assistance Act or the Arms Export Control Act.

The petitioner also states:

* * * The Department of the Army, Navy, and Air Force have under development or have developed depleted uranium munitions which are designed to take advantage of the high density of depleted uranium in order to obtain desired weapons effects against heavily armored targets or for close-in airborne missiles. These munitions will also be made available to foreign governments under grant aid or military sales programs authorized by the Arms Export and Control Act and the Foreign Assistance Act.

Granting a general license to export depleted uranium penetrators would not be inimical to the common defense and security or constitute an unreasonable risk to the public health and safety.

Utilization of a general license for the export of depleted uranium munitions will require that the department of Defense secure approval for any proposed sale of such munitions from the State Department and condition any sale on agreement by the recipient foreign government not to transfer depleted uranium munitions to another country without United States Government approval, not to divert depleted uranium munitons for uses other than their intended purpose, and to comply with United States Government requirements for inventory verification.

A copy of the petition for rule making is available for public inspection in the Commission's Public Document Room, 1717 H Street, NW., Washington, DC. A copy of the petition may be obtained by writing to the Division of Rules and Records, Office of Administration, U.S. Nuclear Regulatory Commission, Washington, DC 20555.

All persons who desire to submit written comments or suggestions concerning the petition for rule making should send their comments to the Secretary of the Commission, U.S. Nuclear Regulatory Commission, Washington, DC 20555, Attention: Docketing and Service Branch by December 4, 1979.

For further information contact: Joseph M. Felton, Director, Division of Rules and Records, Office of Administration, U.S. Nuclear Regulatory Commission, Washington, DC 20555. Telephone: 301-492-7211.

Dated at Washington, DC this 28 day of September 1979.

For the Nuclear Regulatory Commission.

Samuel J. Chilk,

Secretary of the Commission.

[FR Doc. 79-30914 Filed 10-4-79; 8:45 am]

BILLING CODE 7590-01-M

Draft Regulatory Guide; Issuance and Availability

The Nuclear Regulatory Commission has issued for public comment a draft of a new guide planned for its Regulatory Guide Series together with a draft of the associated value/impact statement. This series has been developed to describe and make available to the public methods acceptable to the NRC staff of implementing specific parts of the Commission's regulations and, in some cases, to delineate techniques used by the staff in evaluating specific problems or postulated accidents and to provide guidance to applicants concerning certain of the information needed by the staff in its review of applications for permits and licenses.

The draft guide, temporarily identified by its task number, SC 521-4, is entitled "LWR Core Reloads; Guidance on Applications for Amendments to Operating Licenses and on Refueling and Startup Tests" and is intended for Division 1, "Power Reactors." It identifies the information needed by the NRC staff to conduct appropriate reviews when reactor refueling requires an application for amendment of an operating license. This guide applies to all boiling water reactors and pressurized water reactors.

This draft guide and the associated value/impact statement are being issued to involve the public in the early stages of the development of a regulatory position in this area. They have not received complete staff review, have not been reviewed by the NRC Regulatory Requirements Review Committee, and do not represent an official NRC staff position.

Public comments are being solicited on both drafts, the guide (including any implementation schedule) and the draft value/impact statement. Comments on the draft value/impact statement should be accompanied by supporting data. Comments on both drafts should be sent to the Secretary of the Commission, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, Attention: Docketing and Service Branch, by December 3, 1979.

Although a time limit is given for comments on these drafts, comments and suggestions in connection with (1) items for inclusion in guides currently being developed or (2) improvements in all published guides are encouraged at any time.

Regulatory guides are available for inspection at the Commission's Public Document Room, 1717 H Street NW., Washington, D.C. Requests for single copies of draft guides (which may be reproduced) or for placement on an automatic distribution list for single copies of future draft guides in specific divisions should be made in writing to the U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, Attention: Director, Division of Technical Information and Document Control. Telephone requests cannot be accommodated. Regulatory guides are not copyrighted, and Commission approval is not required to reproduce them.

(5 U.S.C. 552(a))

Dated at Rockville, Maryland this 27th day of September 1979.

For the Nuclear Regulatory Commission.

Guy A. Arlotto,

Director, Division of Engineering Standards, Office of Standards Development.

[FR Doc. 79-30920 Filed 10-4-79; 8:45 am]

BILLING CODE 7590-01-M

[Dcoket Nos. 50-321-SP and 50-366-SP]

Georgia Power Co., et al.; Establishment of Atomic Safety and Licensing Board To Preside in Proceeding

Pursuant to delegation by the Commission dated December 29, 1972, published in the Federal Register (37 FR 28710) and Sections 2.105, 2.700, 2.702, 2.714, 2.714a, 2.717 and 2.721 of the Commission's Regulations, all as amended, an Atomic Safety and Licensing Board is being established in the following proceeding to rule on petitions for leave to intervene and/or requests for hearing and to preside over the proceeding in the event that a hearing is ordered.

Georgia Power Co., et al.

(Edwin I. Hatch Nuclear Plant, Units 1 and 2) Facility Operating License Nos. DPR-57 and NPFD-5

This action is in reference to an Order published by the Commission on August 15, 1979, in the Federal Register (44 F.R. 47820) entitled "Georgia Power Co., et al.; Proposed Issuance of Amendments to Facility Operating Licenses."

The Chairman of this Board and his address is as follows: Herbert Grossman, Esq., Atomic Safety and Licensing Board Panel, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555.

The other members of the Board and their address are as follows: Mr. Glenn O. Bright, Dr. Richard F. Cole, Atomic Safety and Licensing Board Panel, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555.

Dated at Bethesda, Maryland this 27th day of September 1979.

Robert M. Lazo,

Acting Chairman,

Atomic Safety and Licensing Board Panel.

[FR Doc. 79-30916 Filed 10-4-79; 8:45 am]

BILLING CODE 7590-01-M

International Atomic Energy Agency Draft Safety Guide; Availability of Draft for Public Comment

The International Atomic Energy Agency (IAEA) is developing a limited number of internationally acceptable codes of practice and safety guides for nuclear power plants. These codes and guides will be developed in the following five areas: Government Organization, Siting, Design, Operation, and Quality Assurance. The purpose of these codes and guides is to provide IAEA guidance to countries beginning nuclear power programs.

The IAEA Codes of Practice and Safety Guides are developed in the following way. The IAEA receives and collates relevant existing information used by member countries. Using this collation as a starting point, an IAEA Working Group of a few experts then develops a preliminary draft. This preliminary draft is reviewed and modified by the IAEA Technical Review Committee to the extent necessary to develop a draft acceptable to them. This draft Code of Practice or Safety Guide is then sent to the IAEA Senior Advisory Group which reviews and modifies the draft as necessary to reach agreement on the draft and then forwards it to the IAEA Secretariat to obtain comments from the Member States. The Senior Advisory Group then considers the Member State comments, again modifies the draft as necessary to reach agreement and forwards it to the IAEA Director General with a recommendation that it be accepted.

As part of this program, Safety Guide SG-08, "Surveillance of Important Systems and Components in Nuclear Power Plants," has been developed. The Working Group, consisting of Mr. J. Burtheret of France; Mr. P. V. Gujar of India; and Mr. R. E. Denton (Baltimore Gas and Electric Company) of the United States of America, developed the initial draft of this Safety Guide from an IAEA collation during a meeting on February 12-23, 1979. The Working Group draft was modified by the IAEA Technical Review Committee in a meeting on July 2-6, 1979. We are soliciting comments on Revision 2 of this Safety Guide dated July 5, 1979. Comments on this draft received by November 15, 1979 will be useful to the U.S. representatives to the Technical Review Committee and Senior Advisory Group in evaluating its adequacy prior to the next IAEA discussion.

Single copies of this draft may be obtained by a written request to the Director, Office of Standards Development, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555.

(5 U.S.C. 522(a))

Dated at Rockville, Md. this 25th day of September 1979.

For the Nuclear Regulatory Commission.

Robert B. Minogue,

Director, Office of Standards Development.

[FR Doc. 79-30917 Filed 10-4-79; 8:45 am]

BILLING CODE 7590-01-M

Regulatory Guide; Withdrawal

The Nuclear Regulatory Commission staff has withdrawn Regulatory Guide 5.2, "Classification of Unirradiated Plutonium and Uranium Scrap," which was issued December 20, 1972. It endorses two standards, ANSI N15.1—1970, "Classifiction of Unirradiated Uramium Scrap," and ANSI N15.10—1972, "Classification of Unirradiated Plutonium Scrap," that have been withdrawn by the American National Standards Institute. Equivalent recommendations to those contained in the standards and guide have been incorporated in the current material classification codes contained in the instructions for Form NRC-741, "Nuclear Material Transaction Report." The withdrawal of Regulatory Guide 5.2 does not affect any licensing commitments.

Regulatory guides are developed to describe and make available to the public methods acceptable to the NRC staff for implementing specific parts of the Commission's regulations and, in some cases, to delineate techniques used by the staff in evaluating specific problems. Guides may be withdrawn when they are superseded by the Commission's regulations, when equivalent recommendations have been incorporated in applicable approved codes and standards, or when changes in methods and techniques or in the need for specific guidance have made them obsolete.

(5 U.S.C. 552(a))

Dated at Rockville, Maryland, this 26th day of September 1979.

For the Nuclear Regularly Commission.

Robert B. Minogue,

Director, Office of Standards Development.

[FR Doc. 79-30919 Filed 10-4-79; 8:45 am]

BILLING CODE 7590-01-M

[Operating License No. DPR-36]

Maine Yankee Atomic Power Co. [Maine Yankee Atomic Power Plant]; Issuance of Director's Decision Under 10 CFR 2.206

On July 13, 1979, John M. R. Paterson, Deputy Attorney General of the State of Maine, requested on the State's behalf that the Nuclear Regulatory Commission, Office of Inspection and Enforcement, initiate appropriate proceedings to impose penalties against Maine Yankee Atomic Power Company for an alleged violation of the operating license for its Maine Yankee facility. The Director of the Office of Inspection and Enforcement has treated the request as a petition for action under 10 CFR 2.206. Upon a review of Maine Yankee' s license requirements, the Director has determined that no violation of regulatory or license requirements has occurred. Accordingly, the State of Maine's request has been denied.

Copies of the Director's decision are available for inspection in the Commission's Public Document Room, 1717 H Street, N.W., Washington, D.C. 20555, and in the Local Public Document Room at the Wiscasset Public Library, High Street, Wiscasset, Maine 94578. A copy of this decision will also be filed with the Secretary of the Commission for review by the Commission in accordance with 10 CFR 2.296(c) of the Commission's regulations.

In accordance with 10 CFR 2.06(c) of the Commission's regulations, this decision will constitute the final action of the Commission twenty (20) days after the date of issuance, unless the Commission on its own motion institutes a review of this decision within that time.

Dated at Bethesda, Maryland this 27th day of September, 1979.

For the Nuclear Regulatory Commission.

Victor Stello, Jr.,

Director, Office of Inspection and Enforcement.

[FR Doc. 79-30918 Filed 10-4-79; 8:45 am]

BILLING CODE 7590-01-M

[Docket No. 40-8747]

Negative Declaration Regarding Issuance of a Byproduct Material License for Operation of the Hobson Project in Karnes County, Tex.

AGENCY: U.S. Nuclear Regulatory Commission.

ACTION: Notice of Issuance of the Negative Declaration and a Byproduct Material License to Everest Minerals Corporation (40-8747).

SUMMARY: The U.S. Nuclear Regulatory Commission (the Commission) is considering issuing a license to own, use, and possess byproduct material as mill tailings under the Uranium Mill Tailings Radiation Control Act (UMTRCA) (44 FR 47192) for an in-situ uranium extraction operation by Everest Minerals Corporation near Hobson, Texas, in Karnes County. The Division of Waste Management staff has prepared an environmental impact appraisal stating that there will be no significant environmental impact attributable to the action.

The environmental impact appraisal and license is available for public inspection and copying at the Commission's Public Document Room at 1717 H Street, N.W., Washington, D.C. 20555.

SUPPLEMENTARY INFORMATION: Although Texas is an Agreement State for issuing source material licenses, the UMTRCA requires a byproduct material license be issued by the Nuclear Regulatory Commission for in-situ operations involving mill tailings (see 44 FR 47192, describing implementation of this Act). Both liquid and solid tailings wastes will be produced by the proposed operation. Liquid wastes will be disposed by deep well injection and the solid wastes will be transported to a licensed disposal facility.

Dated at Silver Spring, Maryland, this 26th day of September, 1979.

For the Nuclear Regulatory Commission.

Ross A. Scarano,

Chief, Uranium Recovery Licensing Branch, Division of Waste Management.

[FR Doc. 79-30915 Filed 10-4-79; 8:45 am]

BILLING CODE 7590-01-M

THE PRESIDENT'S ADVISORY COMMITTEE FOR WOMEN

Meeting

Pursuant to the provisions of the Federal Advisory Committee Act (Pub. L. 92-463 as amended), notice is hereby given of a meeting of the President's Advisory Committee for Women.

Date, time and place: October 22, 1979.

Open business session: 9:45 a.m.–12:00 Noon, Room N-5437, Department of Labor, 200 Constitution Avenue, NW., Washington, D.C. 20210.

Closed business session: 12:00 Noon to 4:00 p.m., Room N-5437, Department of Labor, 200 Constitution Avenue, NW., Washington, D.C. 20210.

Purpose: A regular scheduled meeting.

Date, time and place: October 24, 1979.

Open meeting: 9:00 a.m.–10:30 a.m., Room N-5437, Department of Labor, 200 Constitution Avenue, NW., Washington, D.C. 20210.

Purpose: Exchange information with Women's Organizations.

The agenda for the meetings will include the following:

October 22

A discussion and evaluation of the September public hearings held in Raleigh, N.C. and plans for the next public hearings.

A portion of this meeting will be closed under the authority of Section 10(d) of the Federal Advisory Committee Act. During its closed session, the Committee will discuss personnel and Committee management.

October 24

A breakfast gathering of invited women's groups to exchange information and plan future cooperation.

Sarita Gattis Schotta,

Executive Director.

September 28, 1979.

[FR Doc. 79-30961 Filed 10-4-79; 8:45 am]

BILLING CODE 4510-23-M

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34-16234/October 2, 1979; File No. SR-PSE-79-13]

Pacific Stock Exchange Inc.; Proposed Rule Change; Self-Regulatory Organizations

Proposed rule change by the Pacific Stock Exchange Incorporated, relating to: Responses to the Recommendations of the Special Study of the Options Markets as promulgated by the Securities and Exchange Commission in Release No. 34-15575.

Comments Requested by: November 2, 1979.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934, 15 U.S.C. 78s as amended by Pub. L. No. 94-29, 16 (June 4, 1975), notice is hereby given that on September 9, 1979 the Pacific Stock Exchange Incorporated filed with the Securities and Exchange Commission proposed rule changes as described in Items I, II and III below, which have been prepared by the self-regulatory organization. The Commission is publishing this notice to solicit comments on the proposed rule changes from interested parties.

The Commission has determined that it is necessary and appropriate to provide additional time for public comment on and Commission consideration of the proposed rule changes. Because the subject filing contains numerous rule proposals which, if approved, would affect significantly the operation of the standardized options markets, the Commission believes that additional time is necessary to enable commentators to address meaningfully the substance of the proposals and to enable the Commission to give the proposals the careful consideration they warrant before determining whether to approve the proposals or to initiate proceedings to determine whether they should be disapproved.

Accordingly, the Commission, pursuant to Section 19(b)(2) of the Act, hereby extends until 90 days from the date of publication of notice of filing of the proposed rule changes captioned above, the time period within which the Commission must either approve the proposed rule changes or institute proceedings to determine whether the proposed rule changes should be disapproved.

I. Self-Regulatory Organizations Statement of Terms of Substance of the Proposed Rule Changes

The following proposed amendments to the Rules of the Pacific Stock Exchange Incorporated ("The PSE") attached hereto reflect the uniform response of a joint SRO task force to certain recommendations of the SEC Options Study, departing from the uniform response only to the extent necessary to conform to the style of the PSE's rules.

Following the text of the proposed rule changes is a table showing the anticipated effective dates of the rule changes expressed as the number of days following Commission approval when the rule changes will go into effect. The interval between Commission approval and effectiveness is to provide member organizations with the time needed to familiarize themselves with the new rules in their final form, and to make the necessary internal administrative and procedural changes necessary to bring themselves into compliance. During this interval, the PSE intends to provide member firms with various educational materials explaining the new rules, and otherwise to assist the firms in complying with them. Since uniformity among SROs is essential to the implementation of the proposed new regulatory requirements, the anticipated time of their becoming effective contemplates that other SROs will institute comparable requirements at the same time. If this condition is not met, the PSE may have to defer the effectiveness of some or all of these rules until substantial uniformity among SROs can be achieved.

In the following proposed amendments to PSE Rules, italics indicates additions and brackets indicate deletions.

Rule X—Conduct of Accounts

Doing a Public Business in Options

Sec. 18. Section 18 shall be applicable to member organizations transacting business with the public in option contracts issued by the Options Clearing Corporation. Except to the extent that specific provisions of this Section 18 govern, or unless the context otherwise requires, the provisions of all other sections of this rule shall be applicable to the conduct of accounts.

(a) Registration of Principals and [Sales] Representatives. No member organization shall be approved to transact business with the public in option contracts, unless those persons associated with the member organization who are designated as Options Principals or who are designated as [Sales] *Registered* Representatives have been approved by and registered with the Exchange as such, pursuant to the provisions of

Section 14 and Section 15, as appropriate, of Rule VI.

(b) Open of Accounts. No member organization shall accept an order from a customer for the purchase or sale (writing) of an option contract unless the customer's account has been approved for options trading in accordance with the provisions of this Section.

(1) [Approval Required—A member organization shall learn the essential facts relative to every customer and shall specifically approve in writing the customer's account for options trading pursuant to the provisions of Section 1(a) of this Rule.]

Diligence in Opening Account. In approving a customer's account for options transactions, a member organization shall exercise due diligence to learn the essential facts as to the customer and his investment objectives and financial situation, and shall make a record of such information which shall be retained in accordance with Section 18(d) of this Rule. Based upon such information (a) the branch office manager or other Registered Options Principal shall approve in writing the customer's account for options transactions: Provided, That if the branch office manager is not a Registered Options Principal, his approval shall within a reasonable time be confirmed by a Registered Options Principal.

(2) Disclosure. At or prior to the time a customer's account is approved for options trading, the member organization shall deliver to the customer a current prospectus as defined in paragraph [(f)] *(g)* of this Section.

(3) Account Agreement. Within 15 days after a customer's account has been approved for options transactions a member organization shall obtain from the customer a written agreement that (i) the customer is aware of and agrees to be bound by the Rules of the [participating exchanges] *Exchange* applicable to the trading of option contracts and the Rules of the Options Clearing Corporation, (ii) the customer agrees not to violate, either alone or in concert with others, the position limits of the exercise limits established by the [participating exchange,] *Exchange* and (iii) the customer acknowledges receipt of a current prospectus.

(4) *Verification of Customer Background and Financial Information. The background and financial information upon which the account of every new customer that is a natural person has been approved for options trading, unless the information is included in the customer's account agreement, shall be sent to the customer for verification within fifteen (15) days after the customer's account has been approved for options transactions. A copy of the background and financial information on file with the member organization shall also be sent to the customer for verification within fifteen (15) days after the member organization becomes aware of any material change in the customer's financial situation.*

Commentary:

.01 [Each member organization should consider employing a separate option account approval form for option customers in conjunction with, or in the case of established accounts, as a supplement to the standard new account approval form so as to ensure the receipt of all the required information and, in the case of established customers, that such information is current.]

In fulfilling its obligations pursuant to paragraph (b)(1) of this Section 18 with respect to options customers that are natural persons, a member organization shall seek to obtain the following information at a minimum (information shall be obtained for all participants in a joint account):

1. Investment objectives (e.g., safety of principal, income, growth, trading profits, speculation)

2. Employment status (name of employer, self-employed or retired)

3. Estimated annual income from all sources

4. Estimated net worth (exclusive of family residence)

5. Estimated liquid net worth (cash, securities, other)

6. Marital status; number of dependents

7. Age

8. Investment experience and knowledge (e.g., number of years, size, frequency and type of transactions) for options, stocks and bonds, commodities, other.

In addition, the customer's account records shall contain the following information, if applicable:

a. Source or sources of background and financial information (including estimates) concerning the customer

b. Discretionary trading authorization: agreement on file name, relationship to customer and experience of person holding trading authority

c. Date prospectus furnished to customer

d. Type of transaction for which account is approved (e.g., buying, covered writing, uncovered writing, spreading)

e. Name of registered representative

f. Name of ROP approving account; date of approval

g. Dates of verification of currency of account information

The member organization should consider utilizing a standard account approval form so as to ensure the receipt of all the required information.

.02. [In connection with approving the account of a customer for options trading, member organizations should seek information in particular as to whether the customer has had prior experience in trading options, whether he is aware of the nature and extent of the obligations as well as the risks attendant to options trading, whether he has accounts with other brokerage firms and the extent of any positions or commitments therein, and whether the customer has financial resources adequate to cover option positions he may intend to establish in such account.

Every member organization has an affirmative obligation to exercise "due diligence" to determine the investment objectives, financial situation and needs of every customer seeking approval to trade exchange options. The member organization shall act through the Registered Options Principal and the Registered Options Representative handling the account and, therefore, the obligation to make the inquiry lies not only with the member organizations but also with the Registered Options Principal and the Registered Options Representative.

The inquiry should attempt to determine pertinent facts about the customer, such as his marital status, dependents, occupation, major sources of income, net worth, investment experience and ability to understand and evaluate the risks of options transactions.

The information concerning the customer shall be recorded and maintained with the customer's new account information. Should a customer decline to provide any or all of the information requested during the inquiry, the Registered Options Principal should note that an inquiry was made and that the customer declined to provide either all or a part of the information requested. A member organization should also consider obtaining a statement from the customer evidencing that he declined to provide this information.

The Registered Options Principal is under an obligation to make a judgment, based upon the information obtained from the customer or based on other information known to the Registered Options Principal, as to the advisability of accepting the customer for exchange options transactions. It is entirely consistent with the intent of Rule X for a customer to be approved only for certain types of options transactions and not others. In light of the suitability provisions, a customer may be approved for one or more of the following types of options transactions: (i) Unsolicited transactions, (ii) purchases and covered writing transactions, (ii) recommended uncovered writing transactions, and (iv) discretionary transactions. Member organizations should consider minimum equities in accounts approved for certain types of options transactions or should consider placing dollar limitations on options transactions of various types.]

Refusal of a customer to provide any of the information called for in Commentary .01 shall be so noted on the customer's records at the time the account is opened. Information provided shall be considered together with other information available in determining whether and to what extent to approve the account for optional transactions.

.03 [Each customer must be approved for exchange options trading prior to the member organization's accepting an exchange option order from the customer. Approval of a customer's account for general securities transactions, including OTC options transactions, which might have taken place prior to the customer's present intention to trade exchange options, does not meet the requirement. Accounts previously approved for other securities transactions must be re-evaluated and approved for exchange options transactions prior to accepting any orders from the customer for exchange options.

A Branch office manager may initially approve accounts for options transactions at his branch office. However, the branch office manager's approval must always be confirmed by the Registered Options Principal. This should ordinarily take place within 10 business days after approval by the branch office manager. Unusual circumstances which preclude the confirmation from taking place within 10 business days should be documented and retained in a separate file at the main office of the member organization.

In all cases, the Registered Options Principal approving or confirming approval of customer account for exchange options transactions shall be an officer or partner of the member organization. Organization's having branch offices are encouraged to qualify as many Registered Options Principals as are necessary to accomplish promptly the review, approval and/or confirmation of approval of customer accounts.]

The requirement of paragraph (b)(4) of this section 18 for the initial and subsequent verification of customer background and financial information may be satisfied by sending to the customer the information required in Items 1 through 6 of Commentary .01 above as contained in the member's records and providing the customer with an opportunity to correct or complete the information. In all cases, absent advice from the customer to the contrary, the information will be deemed to be verified.

[.04 The account agreement required by this paragraph must be executed by the customer and delivered to the member organization not later than 15 days after the account has been first approved for options trading, whether or not an exchange options transaction has been effected for such customer. It is mandatory that this agreement contain a provision stating that the account will be handled in accordance with the Rules of the participating exchanges and of the Options Clearing Corporation. It is also mandatory that this agreement contain a provision stating that the customer, acting alone or "in concert with" others, will not exceed the position and exercise limits established by the Rules of such participating exchanges, Agreements that do not state that the customer will comply with the position and exercise limits thus established fail to meet Exchange requirements.

It is suggested that member organizations include a provision in the agreement spelling out the obligations that are incurred by a customer writing options, and further member organizations may structure the agreement so that it contains a provision whereby the customer will advise the member organization of any significant changes which have taken place in the customer's investment objectives, financial situation and needs.]

[.05 The term "in concert with", as referred to in the above Commentary .04 includes, among other situations, the following:

An individual purchases or sells options for his own account and for the account of a trust or corporation over which he exercises control; two or more customers have an agreement or understanding to coordinate their transactions or decide to divide the contracts allowed between them under the established position limits; an investment adviser, broker or other person executes transactions for accounts with respect to which he has discretionary authority, whether or not he also executes transactions for his own account.

The Exchange may from time to time set different levels of position or exercise limits either for all options or particular option classes or series. Each member organization, Registered Options Principal and Registered Options Representative has an obligation to know and enforce the limits currently in effect.]

[.06 Before approving an account of a trust, pension fund, profit sharing plan or other fiduciary for options trading, a member organization shall be satisfied that the instruments under which the fiduciary is acting permit options trading.]

[.07 Before approving an account with respect to which trading authorization has been granted to a third person who is not an employee of the member organization for options trading, the member organization shall obtain written evidence of the agent's authority to act and that such authority specifically includes options trading.]

[.08 Before approving an account of an investment partnership or an investment club for options trading, the member organization shall obtain written evidence of the authority of the person signing the agreement required by the paragraph to sign such agreement on behalf of such partnership or club, as the case may be, and that such authority specifically includes options trading. Information shall also be obtained with respect to any current long or short option positions of the respective partners or members of the partnership or investment club.]

I.A.1.e. (c) Suitability. (1) No member, member [firm] *organization* or registered person thereof shall recommend to any customer any transaction for the purchase or sale (writing) of an option contract unless such member, member [firm] *organization* or registered person has reasonable grounds to believe that the entire recommended transaction is not unsuitable for such customer on the basis of information furnished by such customer after reasonable inquiry concerning the customer's investment objectives, financial situation and needs and any other information known by such member, member [firm] *organization* or registered person.

(2) [No member, member organization or registered person thereof shall effect with or for any customer of such member or member organization any transaction whereby such customer writes or, after writing, is obligated as a writer with respect to:

(a) A call option contract with respect to any underlying stock, which is not long in the customer's account with the member or member organization or which, at the time of writing in not concurrently purchased by such customer for such account provided that an account shall be deemed long an underlying stock if it is long in a security immediately exchangeable or convertible, pursuant to the provisions of Rule XI (Margins), into such underlying stock; or

(b) A put option contract, unless on the basis of information obtained by such member, member organization or registered person from such customer, after reasonable inquiry, and any other information known by such member, member organization or reasonable basis for believing that the customer, at the time of the transaction, is capable of evaluating the additional risks in such transaction, and has the financial capability to meet reasonably foreseeable margin calls, pursuant to applicable margin requirements with respect to the proposed position in such call option contract or put option contract and the related short position in the underlying stock.]

No member, Registered Options Principal or Registered Representative shall recommend to a customer an opening transaction in any option contract unless the person making the recommendation has a reasonable basis for believing at the time of making the recommendation that the customer has such knowledge and experience in financial matters that he may reasonably be expected to be capable of evaluating the risks of the recommended transaction, and is financially able to bear the risks of the recommended position in the option contract.

[Commentary:]

[.01 Every member organization or registered person thereof who recommends an options transaction to a customer must have reasonable grounds to believe that the recommended transaction is not unsuitable for the customer. In connection with any such recommendation, a reasonable inquiry as to the customer's investment objectives, financial situation and needs must have been made. In the event that the customer has declined to furnish the information requested, an options transaction (other than an uncovered writing transaction, as noted below) may still be recommended to the customer provided that the firm has other information indicating that the recommended transaction is not unsuitable for the customer.]

[.02 Since the risks involved in the purchase of call options depend upon such factors as the relationship between the option's exercise price and the market price of the underlying stock, the time period remaining until the option expires, and price volatility and other characteristics of the underlying stock, such factors should be considered and, where appropriate, brought to the attention of the customer in connection with making a recommendation. Further the customer should be made aware that the Exchange may, from time to time, restrict certain transactions in options where the striking price of the option is not reasonably related to the price of the underlying security.]

[.03 With respect to recommending the writing of an option where the customer does not have a corresponding long position in the underlying security (or in a security) convertible into or exchangeable for the underlying security the Rule imposes more stringent suitability standards than for option transactions generally. Before making any such recommendation, the organization must not only be satisfied that the recommendation is not unsuitable for the customer, but also reasonably believe, on the basis of information furnished by the customer, that the customer is capable of evaluating the risks of the uncovered writing transaction, and has the financial capacity to carry such uncovered position. If the customer does not furnish sufficient information to provide a reasonable basis for such belief, uncovered writing transactions may not be recommended. This requirement also applies to a recommendation that a previously covered writing position be uncovered.]

[.04 In considering the suitability of recommended options transactions, member organizations, Registered Options Principals and Registered Options Representatives will ordinarily begin with the information concerning the customer obtained pursuant to the provisions of this Rule at the time the customer's account was originally approved for options transactions. However, in order that recommendations be based upon reasonably current information concerning the customer, information contained in the account record should be updated if there is a reasonable ground to believe that the information is inaccurate or insufficient because of changed circumstances or otherwise. Such updating may be accomplished in any appropriate way (e.g., oral or written inquiry of the customer).]

(d) Supervision of Accounts

Every member organization shall comply with the provisions of Section 1(b) of Rule X in exercising its supervisory responsibilities. In addition to such provisions, every member organization shall [provide for the diligent supervision of all its customer accounts and all orders in such accounts by a Registered Options Principal who is a general partner or officer of the member organization to the extent such accounts and such orders relate to option contract.] *comply with the following provisions as they relate to its options business.*

I.A.1.g (1) Senior Registered Options Principal. Every member organization shall designate and specifically identify to the Exchange a Senior Registered Options Principal who is an officer (in the case of a corporation) or general partner (in the case of a partnership) of the member organization who shall supervise all of the organization's non-member customer accounts and all orders in such accounts, insofar as such accounts and orders relate to option contracts.

(2) Compliance Registered Options Principal. Member organizations shall designate and specifically identify to the Exchange a Compliance Registered Options Principal, (who may be the Senior Registered Options Principal), who shall have no sales functions and shall be responsible to review and to propose appropriate action to secure the member organization's compliance with securities laws and regulations and Exchange rules in respect of its options business. The Compliance Registered Options Principal shall regularly furnish reports directly to the compliance officer (if the Compliance Registered Options Principal is not himself the compliance officer) and to other senior management of the member organization. The requirement that the Compliance Registered Options Principal shall have no sales functions does not apply to a member organization that has received less than $1,000,000 in gross commissions on options business as reflected in its FOCUS Report for either of the preceding two fiscal years or that currently has 10 or fewer Registered Options Representatives.

I.A1.d. *(3) Maintenance of Customer Record. Background and financial information of customers who have been approved for options transactions shall be maintained at both the branch office servicing the customer's account and the principal supervisory office having jurisdiction over that branch office. Copies of account statements of options customers shall be maintained at both the branch office supervising the accounts and the principal supervisory office having jurisdiction over that branch for the most recent six-month period. Other records necessary to the proper supervision of accounts shall be maintained at a place easily accessible both to the branch office servicing the customer's account and to the principal* *supervisory office having jurisdiction over that branch office.*

I.A.2.e. *(4) Each member organization shall maintain at the principal supervisory office having jurisdiction over the office servicing the customer's account, information to permit review of each customer's options account on a timely basis to determine (i) the compatibility of options transactions with investment objectives and with the types of transactions for which the account was approved; (ii) the size and frequency of options transactions; (iii) commission activity in the account; (iv) profit or loss in the account; (v) undue concentration in any options class or classes, and (vi) compliance with the provisions of Regulation T of the Federal Reserve Board.*

Commentary:

.01 [A] *The Senior* Registered Options Principal may delegate to qualified employees the responsibility and authority for the supervision and control of customer accounts and orders required by the provisions of this paragraph, provided that the *Senior* Registered Options Principal shall have overall authority and responsibility for establishing appropriate procedures of supervision and control over such employees.

.02 Every member organization shall establish, maintain and enforce written procedures which detail the methods used to supervise exchange options transaction. These procedures should also [include the manner in which individual accounts are reviewed, the frequency of review and where within the organization's structure the responsibility for each stage in the review process lies.] *detail the methods used to supervise all non-member customer accounts including all orders in such accounts, insofar as such accounts and orders relate to option contracts.*

[.03 The supervisory review should be designed to enable the Registered Options Principal, or person to whom he has delegated the supervisory responsibility, to analyze the activity in all customer accounts, to detect unusual concentration in any option class, and also to enable such persons to analyze activity in each customer account for suitability, potential churning, any problem with respect to "inside" information, violation of position or exercise limits or any other violations.]

[.04 The review methods should be so designed as to identify customers whose accounts have been approved for recommended and unsolicited transactions and to ascertain whether or not options transactions have been executed within the limits of the original approval.]

[.05 Any problem discovered by the Registered Options Principal or other supervisory personnel in their review of option activity in customer accounts should be investigated. The disposition of all such investigations should be fully documented and maintained in a separate file in the main office of the member organization for review by the Exchange during its examination of the organization. Any serious problems discovered during the supervisory review should be immediately brought to the attention of the Exchange.]

I.A.2.c. & d. (e) Discretionary Accounts. (1) Authorization and Approval *Required.* No [member, partner, officer or employee of a] member organization shall exercise any discretionary power with respect to trading in option contracts in a customer's account, or accept orders for option contracts for an account from a person other than the customer, except in compliance with the provisions of Section 6(a) of this Rule and in addition (i) the written authorization of the customer required by Section 6(a) shall specifically authorize options trading in the account; (ii) the account shall have been accepted in writing by a Registered Options Principal [who is a general partner or officer of the member organization having overall responsibility for option contracts, and such person shall approve and initial all orders with respect to option contracts on the day such orders are entered. In the case of a branch office such discretionary orders may be approved and initialled on the day entered by the branch office manager provided that such approval shall be confirmed within a reasonable time by a Registered Options Principal who is a general partner or officer responsible for option contracts]. *The Senior Registered Options Principal shall review the acceptance of each discretionary account to determine that the Registered Options Principal accepting the account had a reasonable basis for believing that the customer was able to understand and bear the risks of the strategies or transactions proposed, and he shall maintain a record of the basis for his determination. Each discretionary order shall be approved and initialled on the day entered by the branch office manager or other Registered Options Principal, provided that if the branch office manager is not a Registered Options Principal, his approval shall be confirmed within a reasonable time by a Registered Options Principal. Every discretionary order shall be identified as discretionary on the order at the time of entry. Discretionary accounts shall receive frequent appropriate supervisory review by the Compliance Registered Options Principal.* The provisions of this subparagraph shall not apply to discretion as to the price at which or the time when an order given by a customer for the purchase or sale of a definite number of option contracts in a specified security shall be executed.

(2) Prohibited Transactions. No [member, partner, officer or employee of a] member [firm] *organization* having discretionary power over a customer's account shall, in the exercise of such discretion, execute or cause to be executed therein any purchases or sales of option contracts which are excessive in size or frequency in view of the financial resources in such account.

(3) Record of transactions. A record shall be made of every transaction in option contracts in respect to which [a member or a partner, officer or employee of] a member [firm] *organization* has exercised discretionary authority, clearly reflecting such fact and indicating the name of the customer, the designation and number of the option contracts, the premium and the date and time when such transaction was effected.

(4) Options Programs. Where the discretionary account involves the systematic use of one or more options strategies, the customer shall be furnished with a written explanation, meeting the requirements of Rule VI, Section 35, of the nature and risks of such strategies.

[Commentary:]

[.01 No transactions shall be executed in a discretionary account which would result in an uncovered short position in option contracts or in the uncovering of any existing short position in option contracts unless the person for whom the account is maintained has specifically authorized, in writing, transactions of this nature and such transactions are effected with due regard to the provisions of this paragraph (d).]

[.02 Member organizations are required to obtain the written authorization of customers prior to the exercise of discretionary power with respect to exchange options transactions in their accounts. Furthermore, a Registered Options Principal who is an officer or general partner of the member organization shall approve discretionary accounts in writing before discretionary power may be exercised with respect to such accounts. It is consistent to handle discretionary accounts for options transactions wherein limited discretionary power has been authorized. For example, discretionary power may be granted for closing existing positions or exercising existing contracts.]

[.03 In addition to identifying the transactions as discretionary, it should also be identified according to name of customer, account designation, number of contracts, premium, date and time the transactions took place and all other pertinent information.]

[.04 Discretionary accounts present special surveillance responsibilities for member organizations and Registered Options Principals. The Exchange recommends that discretionary accounts be reviewed by the Registered Options Principal on a basis more frequent than he would review other accounts. The frequency of this review would depend upon the activity in the account. Such review should look for potential abuses such as excessive transactions prohibited by the Rule. Further, in view of the special surveillance responsibilities associated with discretionary accounts, the Exchange recommends that methods used for supervising discretionary accounts be separately described in the member organization's written procedures.]

Paragraph (f). No change.

Paragraph (g). No change.

Paragraph (h). No change.

Paragraph (i). No change.

(j). Statement of Accounts.

Statements of account required by Section 15 of this rule shall be sent not less frequently than once every month to each customer in whose account there has been an entry during the preceding month with respect to an option contract.

I.A.1.c. *The statement shall bear a legend requesting the customer to promptly advise the member of any material change in the customer's investment objectives or financial situation.*

Paragraph (k). No change.

I.A.1.f. *(l) Customer Complaints.* (1) *Every member organization conducting a non-member customer business shall make and keep current a separate central log, index or other file for all options-related complaints, through which these complaints can easily be identified and retrieved. The term "options-related complaint" shall mean any written statement by a customer or person acting on behalf of a customer alleging a grievance arising out of or in connection with listed options. The central file shall be located at the principal place of business of the member organization or such other principal office as shall be designated by the member organization. At a minimum, the central file shall include: (i) Indentification of complainant, (ii) date complaint was received, (iii) identification of Registered Representative servicing the account, (iv) a general description of the matter complained of, and (v) a record of what action, if any, has been taken by the member organization with respect to the complaint. Each options-related complaint received by a branch office of a member organization shall be forwarded to the office in which the separate, central file is located not later than thirty days after receipt by the branch office. A copy of every options-related complaint shall be maintained at the branch office that is the subject of the complaint.*

I.A.2.b. *(m) Branch Offices of Member Organizations. No branch office of a member organization shall transact options business with the public unless the manager of such branch office has been qualified as a Registered Options Principal; provided, that this requirement shall not apply to branch offices in which not more than three Registered Representatives are located so long as the member organization can demonstrate that the options activities of such branch offices are appropriately supervised by a Registered Options Principal.*

Rule III. Members Trading

Disciplinary Action by Other Organizations

I.A.1.h. Section 11. Every member organization shall promptly notify the Exchange in writing of any disciplinary action, including the basis therefor, taken by any national securities exchange or association, clearing corporation, commodity futures market or government regulatory body against the member organization or its associated persons, and shall similarly notify the Exchange of any disciplinary action taken by the member organization itself against any of its associated persons involving suspension, termination, the withholding of commissions or imposition of fines in excess of $2500, or any other significant limitation on activities.

Rule VI. Exchange Options Trading

[Advertisements, Market Letters and Sales Literature Relating to Options]

Communications to Customers

Section 35.

[(a) Approval by Registered Options Principal. All advertisements, market letters and sales literature issued by a member organization pertaining to options shall be approved in advance by a general partner or officer of the member organization who is a Registered Options Principal, and copies thereof, together with the names of persons approving their issuance, the names of the persons who prepared the material and the source of any recommendations contained therein shall be retained by the member organization and kept readily available for examination by the Exchange for a period of three years.]

[(b) Standards of Approval. No advertisement, market letter or sales literature shall be approved under paragraph (a) of this Section which:

(i) Contains any untrue statement or omission of a material fact or is otherwise false or misleading;

(ii) Would constitute a prospectus as that term is defined in the Securities Act of 1933, unless it meets the requirements of Section 10 of said Act; or

(iii) Otherwise fails to meet the standards of Rule XVI of the Exchange Rules.]

[(c) Exchange Approval Required for Options Advertisement. In addition to the approval required by paragraph (a) of this Section, every advertisement of a member organization pertaining to options shall be submitted to the Department of Member Organizations of the Exchange at least ten days prior to use (or such shorter period as the Department may allow in particular instances), and, if expressly disapproved by the Exchange, shall be withheld or withdrawn from circulation until any changes specified by the Exchange have been made and the advertisement resubmitted for Exchange approval. The requirements of this paragraph shall not be applicable to advertisements submitted to an approved by another national securities exchange or national securities association (having similar requirements regarding approval of advertisements) pursuant to an arrangement approved by the Exchange.]

[(d). Definitions. For purposes of this Section, the following definitions shall apply:

(i) The term "advertisement" shall include any material for use in any newspaper or magazine or other public media or by radio, telephone recording, motion picture or television. (ii) The terms "market letter" and "sales literature" shall include any communication for distribution to customers or the public which contains any analysis, report, recommendation, opinion, prediction or comment with respect to options, underlying stocks or market conditions pertaining thereto.]

[Commentary:]

[.01 In addition to adhering to the general standards of truthfulness and good taste prescribed by Rule XVI of the Exchange Rules, the advertisements, market letters and sales literature of Exchange member organizations pertaining to exchange traded options (options contacts issued or to be issued by the Options Clearing Corporation) should reflect the following factors:]

[I. Exchange traded options are securities registered under the Securities Act of 1933, and are the subject of a currently effective registration statement. Section 5 of the Securities Act prohibits the use of any written material or radio or television advertisements (or other material constituting a "prospectus" as defined in the Act) relating to a registered security unless certain conditions are met. With respect to advertisements and sales literature pertaining to exchange traded options, the following must be observed:]

[A. Except as provided in paragraph B below, no written material with respect to exchange traded options may be sent to any person unless prior to or at the same time with the written material a current prospectus of the Options Clearing Corporation was sent to such person.]

[B. Advertisement (including letters designed for a customer mailing) may be used (and copies of the advertisements may be sent to persons who have not received a prospectus of the Options Clearing Corporation) if the material meets the requirements of Rule 134 under the Securities Act of 1933, as that Rule has been interpreted as applying to exchange traded options. Under Rule 134 advertisements must be limited to general descriptions of the security being offered and of its issuer. In the case of exchange traded options, advertisements under this Rule must have the following characteristics:

(i) The advertisement should state the name and address of the person from whom a current prospectus of the Options Clearing Corporation may be obtained (this would usually be the member organization sponsoring the advertisement);

(ii) The text of the advertisement may contain a brief description of such options, including a statement that the issuer of every such option is the Options Clearing Corporation. The test may also contain a brief description of the general attributes and method of operation of the exchange or exchanges on which such options are traded and the Options Clearing Corporation, including a discussion of how the price of an exchange traded option is determined on the trading floor(s) of such exchange(s);

(iii) The advertisement may include any statement required by any state law or administrative authority;

(iv) Advertising designs and devices including borders, scrolls, arrows, pointers, multiple and combined logos and unusual type faces and lettering as well as attention-getting headlines and photographs and other graphics may be used, provided such material is not misleading.]

[II. There are special risks attendant to options transactions and certain options transactions involve complex investment strategies. These factors should be reflected in any communication (including advertising, sales literature and similar material) which purports to include any discussion of the uses or advantages of exchange traded options. Although it is up to each member organization in preparing its communications concerning such options to take into consideration these factors, the following points of particular importance are pre- [A. Any statement referring to the opportunities or advantages presented by exchange traded options should be balanced by a statement of the corresponding risks. The risk statement should reflect the same degree of specificity as the statement of opportunities, and broad generalities should be avoided. Thus, a statement such as, "With options, an investor has an opportunity to earn profits while limiting his risk of loss," should be balanced by a statement such as, "Of course, an options investor may lose the entire amount committed to options in a relatively short period of time."]

[B. It should not be suggested that options are suitable for most investors, or for small investors. Indeed, it is strongly suggested that there be included in all literature discussing the uses of exchange traded options a warning to the effect that options are not for everybody.]

[C. The mechanism for trading of exchange traded options in the context of an exchange auction market is relatively new, and adequate experience with such trading under varying market conditions is presently lacking. Accordingly, the statements suggesting the certain availability of a secondary market for exchange traded options should be avoided. Instead, references to the secondary market should be expressed in such terms as, "The secondary markets on exchanges for exchange traded options are intended to provide a means for the liquidation of positions in such options", or, "If the price of the underlying stock goes down, the holder of an exchange traded option may be able to realize any remaining value of the option by selling it in the secondary market on an exchange where such option is listed."]

(a) General Rule. No member or member organization, and no partner or employee thereof, shall utilize any advertisement, sales literature or other communications to customers or the public concerning options which:

(i) Contains any untrue statement or omission of a material fact or is otherwise false or misleading;

(ii) Contains promises of specific results, exaggerated or unwarranted claims, opinions for which there is no reasonable basis or forecasts of future events which are unwarranted or which are not clearly labeled as forecasts;

(iii) Contains hedge clauses or disclaimers which are not legible, which attempt to disclaim responsibility for the content of such literature or for opinions expressed therein, or which are otherwise inconsistent with such advertisement or sales literature;

(iv) Fails to meet general standards of good taste and truthfulness; or

(v) Would constitute a prospectus as that term is defined in the Securities Act of 1933, unless it meets the requirements of Section 10 of said Act.

(b) Approval by Compliance Registered Option Principal. All advertisements and sales literature (except completed worksheets) issued by a member or member organization pertaining to options shall be approved in advance by the Compliance Registered Options Principal or his designee. Copies thereof, together with the names of the persons who prepared the material, the names of the persons who approved the material and, in the case of sales literature, the source of any recommendations contained therein, shall be retained by the member or member organization and be kept at an easily accessible place for examination by the Exchange for a period of three years.

(c) Exchange Approval Required for Options Advertisements. In addition to the approval required by paragraph (b) of this Section, every advertisement of a member or member organization pertaining to options shall be submitted to the Compliance Department of the Exchange at least ten days prior to use (or such shorter period as the Department may allow in particular instances) for approval and, if changed or expressly disapproved by the Exchange, shall be withheld from circulation until any changes specified by the Exchange have been made or, in the event of disapproval, until the

advertisement has been resubmitted for, and has received, Exchange approval. The requirements of this paragraph shall not be applicable to:

(i) Advertisements submitted to another self-regulatory organization having comparable standards pertaining to advertisements; and

(ii) Advertisements in which the only reference to options is contained in a listing of the services of a member organization.

(d) Except as otherwise provided in the Commentary hereunder, no written materials respecting options may be disseminated to any person who has not previously or contemporaneously received a current Clearing Corporation prospectus.

(e) Definitions. For purposes of this Rule, the following definitions shall apply:

(i) The terms "advertisement" shall include any sales material that reaches a mass audience through public media such as newspapers, periodicals, magazines, radio, television, telephone recording, motion picture, audio or video device, billboards, signs, or through written communications to customers or the public not required to be accompanied or preceded by a current Clearing Corporation prospectus.

(ii) The term "sales literature" shall include any written communication (not defined as an "advertisement") distributed or made available to customers or the public that contains any analysis, performance report, projection or recommendation with respect to options, underlying securities or market conditions, any standard forms of worksheets, or any seminar text which pertains to options and which is communicated to customers or the public at seminars, lectures or similar such events, or any Exchange-produced materials pertaining to options.

Commentary:

.01 The special risks attendant to options transactions and the complexities of certan options investment strategies shall be reflected in any communication which discusses the uses or advantages of options. In the preparation of communications respecting options, the following guidelines shall be observed:

A. Any statement referring to the potential opportunities or advantages presented by options should be balanced by a statement of the corresponding risks. The risk statement should reflect the same degree of specificity as the statement of opportunities, and broad generalities should be avoided. Thus, a statement such as "with options, an investor has an opportunity to earn profits while limiting his risk of loss", should be balanced by a statement such as "of course, an options investor may lose the entire amount committed to options in a relatively short period of time."

B. It should not be suggested that options are suitable for all investors. All communications discussing the use of options should include a warning to the effect that options are not for everyone.

C. Statements suggesting the certain availability of a secondary market for options should not be made.

.02 Advertisements pertaining to options shall conform to the following standards:

A. Advertisements may only be used (and copies of the advertisements may be sent to persons who have not received a Clearing Corporation prospectus) if the material meets the requirements of Rule 134 under the Securities Act of 1933, as that Rule has been interpreted as applying to options. Under Rule 134, advertisements must be limited to general descriptions of the security being offered and of its issuer. Advertisements under this Rule shall state the name and address of the person from whom a current Clearing Corporation prospectus may be obtained. Such advertisements may have the following characteristics:

(i) The text of the advertisement may contain a brief description of such options, including a statement that the issuer of every such option is the Clearing Corporation. The text may also contain a brief description of the general attributes and method of operation of the exchange or exchanges on which such options are traded and of the Clearing Corporation, including a discussion of how the price of an option is determined on the trading floor(s) of such exchange(s);

(ii) The advertisement may include any statement required by any state law or administrative authority;

(iii) Advertising designs and devices, including borders, scrolls, arrows, pointers, multiple and combined logos and unusual type faces and lettering as well as attention-getting headlines and photographs and other graphics may be used, provided such material is not misleading.

B. The use of recommendations or of past or projected performance figures, including annualized rates of return, is not permitted in any advertisement pertaining to options.

.03 Written communications (other than advertisements) pertaining to options shall conform to the following standards:

A. Such communications shall state that supporting documentation for any claims (including any claims made on behalf of options programs or the options expertise of sales persons), comparisons, recommendations, statistics or other technical data, will be supplied upon request.

B. Such communications may contain projected performance figures (including projected annualized rates of return) provided that:

(i) No suggestion of certainty of future performance is made;

(ii) Parameters relating to such performance figures are clearly established (e.g., to indicate exercise price of option, purchase price of the underlying stock and its market price, option premium, anticipated dividends, etc.);

(iii) All relevant costs, including commissions and interest charges (if applicable with regard to margin transactions) are disclosed;

(iv) Such projections are plausible and are intended as a source of reference or a comparative device to be used in the development of a recommendation;

(v) All material assumptions made in such calculations are clearly identified (e.g., "assume option expires", "assume option unexercised", "assume option exercised", etc.);

(vi) The risks involved in the proposed transactions are also discussed;

(vii) In communications relating to annualized rates of return, that such returns are not based upon any less than a sixty-day experience; any formulas used in making calculations are clearly displayed; and a statement is included to the effect that the annualized returns cited might be achieved only if the parameters described can be duplicated and that there is no certainty of doing so.

C. Such communications may feature records and statistics which portray the performance of past recommendations or of actual transactions, provided that:

(i) Any records or statistics must be confined to a specific "universe" that can be fully isolated and circumscribed and that covers at least the most recent 12-month period;

(ii) Such communications include or offer to provide the date of each initial recommendation or transaction, the price of each such recommendation or transaction as of such date, and the date and price of each recommendation or transaction at the end of the period or when liquidation was suggested or effected, whichever was earlier;

(iii) Such communications disclose all relevant costs, including commissions

and interest charges (if applicable with regard to margin transactions) and, whenever annualized rates of return are used, all material assumptions used in the process of annualization;

(iv) In the event such records or statistics are summarized or averaged, such communications include the number of items recommended or transacted, the number that advanced and the number that declined;

(v) An indication is provided of the general market condition during the period(s) covered, and any comparison made between such records and statistics and the overall market (e.g., comparison to an index) is valid;

(vi) Such communications state that the results presented should not and cannot be viewed as an indicator of future performance; and

(vii) A Registered Options Principal determines that the records or statistics fairly present the status of the recommendations or transactions reported upon and so initials the report.

D. In the case of an options program (i.e., an investment plan employing the systematic use of one or more options strategies), the cumulative history or unproven nature of the program and its underlying assumptions shall be disclosed.

E. Standard forms of options worksheets utilized by member organizations, in addition to complying with the requirements applicable to sales literature, must be uniform within a member organization.

F. Communications that portray performance of past recommendations or actual transactions and completed worksheets shall be kept at a place easily accessible to the sales office for the accounts or customers involved.

Rule VI—Allocation of Exercise Assignment Notices

I.A.l.m. Section 31.

(a) Each member organization shall establish fixed procedures for the allocation of exercise notices assigned in respect of a short position in option contracts in such member [firm's] *organization's* customers' accounts. Such allocation shall be on a "first in, first out" [basis, on a basis of] *or automated* random selection [or on the basis of another allocation method that is fair and equitable to the customers of such member organization: *Provided, however,* That such method of allocation may provide that an exercise notice of block size will to the extent possible be allocated to a customer or customers having an open short position of block size and that an exercise notice of less than block size will to the extent possible be allocated to a customer having a short position of less than block size: *And provided further,* That the Member Organization shall allocate an exercise notice pertaining to a call option contract to a customer who has made a specific deposit of the underlying security if it is directed to do so by the Clearing Corporation. For the purpose of this Section, an exercise notice or a short position with respect to 25 or more units of trading of the same class of options shall be deemed to be of "block size".] *basis that has been approved by the Exchange or on a manual random selection basis that has been specified by the Exchange. Each member organization shall inform its customers in writing of the method it uses to allocate exercise notices to its customers' accounts, explaining its manner of operation and the consequences of that system.*

(b) Each member organization shall report its proposed method of allocation to the Exchange and obtain the Exchange's prior approval thereof, and no member organization shall change its method of allocation unless the change has been reported to and been approved by the Exchange. [Each member organization shall, upon the request of a customer, furnish to such customer a description of the method used by it in assigning exercise notices to the accounts of customers.] *The requirements of this paragraph shall not be applicable to allocation procedures submitted to another self-regulatory organization having comparable standards pertaining to methods of allocation.*

I.A.l.n.

(c) Each member organization shall preserve for a three-year period sufficient work papers and other documentary materials relating to the allocation of exercise assignment notices to establish the manner in which allocation of such exercise notices is in fact being accomplished.

Commentary

.01 When a member organization clears all of its transactions, both proprietary and customer transactions, through another member organization in a single omnibus account, exercise notices allocated to the non-clearing member organization's omnibus account shall first be allocated, *in accordance with this Rule,* on a fair and equitable basis between the proprietary and customer accounts of the non-clearing member organization and then allocated among the customer accounts in accordance with paragraph (a) of this Section.

Rule VI

[Interest In Joint Accounts]

Securities Accounts and Orders of Market Makers

I.A.l.o. Section 81.

(a) Identification of Accounts. In a manner prescribed by the Exchange, each Market-Maker shall file with the Exchange and keep current a list identifying all accounts for stock, option, and related securities trading in which the Market-Maker has an interest or may engage in trading activities or over which he exercises investment discretion. No Market-Maker shall engage in stock, option, or related securities trading in an account which has not been reported pursuant to this Rule.

I.A.l.p.

(b) Reports of Orders. In a manner prescribed by the Exchange, each Market-Maker shall, on the business day following order entry date, report to the Exchange every order entered by the Market-Maker for the purchase or sale of a security underlying options traded on the Exchange or a security convertible into or exchangeable for such underlying security as well as opening and closing positions in all such securities held in each account reported pursuant to this Rule. The report pertaining to orders must include the terms of each order, identification of the brokerage firms through which the orders were entered, the times of entry or cancellation, the times reports of executions were received and, if all or part of the order was executed, the quantity and execution price.

(c) Joint Accounts. No Market-Maker shall, directly or indirectly, hold any interest or participate in any joint account *for buying or selling any option contract unless each participant in such joint account is a member or member organization and unless such account is reported to and not disapproved by the Exchange. Such reports in a form prescribed by the Exchange shall be filed with the Exchange before any transaction is effected on the Exchange for such joint account.*

Commentary

.01 Each participant in such joint account shall be jointly and severally responsible for assuring that the account complies with the provisions of the Exchange Constitution Rules, Commentaries and procedures.

.02 In order to establish a joint account which acts in the capacity of a Market-Maker, there may not be more than two participants of which at least one shall be an individual who is

registered as a Market-Maker. If the other participant in such joint account is to be a member organization, it shall either (a) have a registered Market-Maker register his membership for the organization, (b) have a nominee of the organization who is a registered Market-Maker or (c) be a clearing number which clears and carries such joint account. All references herein to individuals registered as Market-Makers shall mean those having appointments under Section 79 of this Rule. Member organizations meeting the requirements of (a) and (b) above who participate in joint accounts shall be deemed to be registered as Market-Makers for the purpose of transactions in such accounts.

.03 Each participant in a joint account must:

(a) file with the Membership Services Department and thereafter keep current a completed application on such form as is prescribed by the Exchange;

(b) be registered in accordance with the provisions of Section 15(a)(i) of the Securities Exchange Act of 1934.

.04 Participants in the joint account shall not execute transactions with the joint account or among themselves either as Floor Broker or Market-Maker.

.05 Reports of accounts that need to be filed with the Exchange pursuant to this Rule relate only to accounts in which a Market-Maker, as an individual, directly or indirectly, controls trading activities. Thus, reports would be required for accounts over which a Market-Maker exercises investment discretion as well as his proprietary accounts. Reports would not be required simply because of a Market-Maker's passive interest in his firm's proprietary accounts. For purposes of this Rule, related securities include securities convertible into or exchangeable for underlying securities.

Effectiveness Timetable

Rule	No. of days following Commission approval
X, Section 18(b)(1)	30 days.
X, Section 18(b)(4)	30 days for initial verification, 60 days for subsequent verification.
X, Section 18(c)	30 days.
X, Section 18(d)(1)	30 days.
X, Section 18(d)(2)	80 days.
X, Section 18(d)(3)	90 days.
X, Section 18(e)(1)	60 days.
X, Section 18(e)(4)	80 days.
X, Section 18(j)	90 days.
X, Section 18(l)	60 days.
X, Section 18(m)	80 days.
III, Section 11	30 days.
Proposed Rule XX, Section 1	Immediately upon approval of rule filing.
VI, Section 35(a)	Immediately.
VI, Section 35(b)	80 days; until then approval under present Rule X, Section 35(a).
VI, Section 35 (c), (d), and (e)	Immediately.
VI, Section 31(a)	60 days.
VI, Section 31(b)	Immediately.
VI, Section 31(c)	60 days.
VI, Section 81 (a) and (b)	60 days.

II. Self-Regulatory Organization's Statement of Purpose and Statutory Basis of Proposed Rule Changes

In its filing with the Commission, the self-regulatory organization included the following statements concerning the purpose and basis of the proposed rule change and discussed comments it received on the proposed rule change. Such statements are reproduced in sections (A), (B) and (C) below.

(A) Self-Regulatory Organization's Statement of Purpose of and Statutory Basis for Proposed Rule Changes

The rule changes filed herewith represent responses to the recommendations of the Special Study of the Options Markets as promulgated by the Commission in Release No. 34-15575.

A discussion of the purpose of each of the rule changes included in this filing is presented below under the caption of the respective recommendation of the Options Study to which the rule change is responsive. To facilitate the Commission's review, the captions of the various responses to recommendations of the Options Study are keyed to the numbering system used in Release No. 34-15575.

The statutory basis for these rule changes, as stated in Release No. 34-15575, is that the implementation of the recommendations of the Options Study is "[c]onsistent with the scheme of self-regulation embodied in the Securities Exchange Act of 1934."

I.A.1.a, b, and c. Rule X, Section 18(b)

These related recommendations call for the collection and recording of background and financial information concerning customers in order to support the approval of their accounts for options transactions and subsequent suitability determinations, and they also call for the verification by the customer of this information. In response, we propose to add a new Commentary .01 to Rule X, Section 18(b), governing the opening of accounts, that lists specific categories of minimum information that a member organization must seek to obtain before opening an options account for a customer. We have not required that all member organizations adopt a uniform options customer information form, since we believe it appropriate to permit the firms to have some flexibility in this regard, so long as the minimum information required by Commentary .01 is included. However, we understand on the basis of discussion with representatives of the Securities Industry Association that the SIA expects to develop and make available contemporaneously with the effective date of this Commentary a standard options customer information form that would satisfy the new requirements.

We also propose to add specific record keeping requirements applicable to options customer information by including in Section 18(b)(1) of Rule X a cross-reference to the provisions of Section 18(d) of Rule X that state how options customer information should be maintained. (See I.A.1.d. below.)

Section 18(b)(4) of Rule X will require that every new options customer that is a natural person be sent for his verification the background and financial information reflected in his customer account information form within 15 days of the approval of his account for options transactions. In addition, this information must again be sent to the customer for verification whenever the firm is aware of any material change in the customer's financial situation. Customer account statements will contain a legend asking that customers notify the firm of any changes in their financial situation (see proposed change to Rule X, Section 18(j)).

I.A.1.d. (Rule X, Section 18(d)

In response to this recommendation concerning the maintenance of records of customer background and financial information, we propose to add to Rule X, Section 18(d) a requirement that background and financial information of customers approved for options transactions must be maintained both at the branch office and at the principal supervisory office having jurisdiction over the branch office. In addition, Rule X, Section 18(d) will require that monthly account statements for the most recent six months be maintained at both offices and that other records necessary to the proper supervision of accounts be easily accessible to both offices. With these new record keeping requirements, not only the registered representative servicing a customer's account, but also the persons responsible for supervising the registered representative, will have easy access to all relevant information concerning the customer and his account.

I.A.1.e. (Rule X, Section 18(c)

The purpose of the proposed amendment to Rule X, Section 18(c) is to make applicable to all recommended opening options transactions the more stringent suitability requirements (that the customer be able to evaluate the risks of the transaction and be financially able to bear them) that now apply only to recommendations for uncovered call writing or put writing. Under the amended suitability rule, a broker-dealer would be prohibited from recommending any opening options transaction to a customer unless these requirements are met.

I.A.1.f. (Rule X, Section 18(1)

In response to the recommendation that copies of customer complaints be maintained at a central office and at relevant branch offices, the PSE proposes to adopt new Section (1) to Rule X. This will require member firms to maintain a central, firm-wide file of all options-related complaints containing specified information concerning each complaint. Copies of the complaints themselves would also be forwarded to and maintained at the same central location. In addition, a copy of every options-related complaint would be maintained at the branch office that is the subject of the complaint.

I.A.1.g. (Rule X, Section 18(d)

This proposed amendment to Rule X, Section 18(d) would require member organizations that do a public business to specifically identify a Compliance Registered Options Principal having no sales functions to be responsible for the review of the firm's options compliance program and to propose any appropriate remedial action. Final responsibility for supervision over all of the firm's options activities would remain with the SROP, although the CROP would be required to furnish reports on a regular basis directly to the firm's senior management. The separation of responsibilities between the CROP and the SROP (except in those firms that choose to have a non-sales SROP) provides for audit of compliance by someone having no sales functions, and yet recognizes that the leadership of most securities firms appropriately has and will continue to have sales functions in combination with supervisory responsibilities. In order to avoid placing unacceptable economic burdens upon smaller firms, the requirment for a non-sales CROP will not apply to firms earning less than $1,000,000 in options commissions or having 10 or less options registered representatives.

I.A.1.H. (Rule III, Section 11 and proposed Rule XX)

The proposed adoption of Rule III, Section 11 adds the requirement for notification to the Exchange of disciplinary action taken against members. As drafted, the rule will call for written notification of disciplinary action taken against persons associated with a member organization as well as against the member organization itself, including notification of significant action taken by the member organization against its associated persons.

In a separate filing on Form 19b-4A the PSE plans to file with the SEC a proposed rule change designated Rule XX, to adopt disciplinary proceedings. Section 10(a) of proposed Rule XX provides for continuing disciplinary jurisdiction over terminated members, member organizations, or persons associated with a member, so long as an inquiry is commenced within one year following written notice of such termination.

I.A.1.i.j.k, and 1. and *I.A.3.a,b and c. Rule VI, Section 35*

The PSE proposes to expand existing rule VI, Section 35, which currently deals with advertisements, market letters and sales literature, to cover all communications to customers. The expanded rule, together with Commentaries thereunder, will incorporate a number of different recommendations of the Options Study.

Proposed revisions to Rule VI, Section 35, are designed to require the approval by the Compliance Registered Options Principle of all communications to customers and to further define the standards applicable to such communications. The Rule would also provide for better coordination among the self-regulatory organizations with respect to the approval of advertisements. Commentaries .01, .02 and .03 contain further detail concerning what should or should not be included in particular type of communications to customers.

The recommendations that relevant costs and other assumptions used in computing annualized rates of return must be disclosed will be included in Commentary .03 under the Rule. This Commentary also contains other standards and disclosure requirements pertaining to projected performance figures. Other provisions of Commentary .03 would impose requirements applicable to options work sheets utilized by member firms, including the requirement that such work sheets must be uniform within a given firm. Completed work sheets would be required to be retained by member firms the same as all other written communications to customers. Commentary .03 also includes performance reports within the definition of "sales literature", and requires that they be approved by the Compliance Registered Options Principle and retained by the firm, and it contains standards for performance reports to assure that each such report is confined to a specifically identifiable and relevant universe.

Finally, the rule and its Commentaries contemplate the distribution to all member organizations of a publication entitled "Guidelines for Options Communications" that would provide further information concerning the standards applicable to communications to customers.

I.A.1.m. (Rule VI, Section 31)

The PSE proposes to amend Rule VI, Section 31 by requiring members who choose to utilize random allocation of exercise notices to use either an automated method that has been approved by an SRO, or the manual method that has been uniformly specified by all of the SROs. FIFO methods of allocation must also be approved by an SRO. Members will be required to notify their customers of the method of allocation utilized, explaining how it works.

I.A.1.n. (Rule VI, Section 31)

The PSE proposes adding to Rule VI, Section 31, a requirement that records relating to exercise allocation be preserved for three years. This period of retention will facilitate auditing compliance by member organizations with required methods of exercise allocation.

I.A.1.o and p. (Rule VI, Section 81)

Rule VI, Section 81 will be amended by adding a new requirement that Market-Makers must inform the Exchange of all of the accounts in which they trade stock or options, and must also notify the Exchange of all orders for, and positions in, underlying securities and related securities. Both of these requirements will improve Exchange surveillance over the options-related trading activities of Market-Makers.

I.A.2.b. (Rule X, Section 18(m)

The proposed adoption of this Rule will require every branch manager to be qualified as a ROP, unless the branch office has not more than three RRs, and is otherwise under the supervision of a ROP. This requirement is one of a number of changes intended to improve internal supervision of member organizations' options activities.

I.A.2.c. and d. (Rule X, Section 18(e)

The proposed amendment to this Rule will require that customers over whose accounts member organizations exercise investment discretion must be furnished with a written explanation of the risks involved in the systematic use of one or more options strategies in these accounts. All such descriptive material would be required to meet the "sales literature" minimum standards of the proposed "Communications to Customers" rule. The amendment would also require that the SROP review the acceptance of each discretionary account to determine whether the ROP accepting the account had a reasonable basis for believing that the customer was able to understand and bear the risks of the proposed strategies or transactions. Under existing Rule X, Section 18(e), a ROP must personally accept every discretionary account, and the added step of a SROP's review of the ROP's acceptance is intended to provide an additional level of supervisory audit over the acceptance of these kinds of accounts.

(B) Self-Regulatory Organization's Statement on Burden on Competition

The PSE recognizes that, as is pointed out in several of the comments received from members, certain of the proposed rule changes will increase the costs to member of handling customers' options transactions, which in turn may place smaller member organizations at a competitive disadvantage. The Commission will have to determine whether the possible competitive burden of these rule changes is necessary or appropriate in furtherance of the Act in deciding whether to approve these rule changes.

(C) Self-Regulatory Organization's Statement on Comments Received From Members, Participants, or Others on Proposed Rule Changes

Comments on the proposed rule changes were solicited and received from members in several ways. First, representatives of the Securities Industry Association attended and actively participated in most of the meetings of the joint SRO task force that developed the rule changes. Second, a preliminary draft of the rule changes was mailed to every member of each of the SROs involved, with a request that comments be forwarded to any one of the seven signatory SROs. A large number of detailed comments were received in response to this mailing; these are available for copying in the Commission's Public Reference Room. Many of the comments received in response to the preliminary draft led to revisions in the rule changes that are reflected in the proposals presented in Item 1 hereof. Where the SROs determined not to make changes in response to member comments, often the SROs were sympathetic to the concerns raised by the commentators, but felt that these concerns were outweighed by the emphasis that the Commission had placed upon the particular rule change that was the subject of the comment. The following is a summary of those comments received from members that are relevant to the proposed rule changes in their present form.

Recommendations I.A.1.a.–c. (Opening of Accounts). A number of members commented that many customers will consider it burdensome and an invasion of privacy to have to provide personal financial information to their brokers, and will refuse to do so. Others questioned the relevance of much of the information that must be sought. In response to these comments, the list of information that must be obtained has been reduced, as explained in Item 3 above. Vertification of customer information was subject to much criticism as being very expensive (especially for smaller firms) and not likely to be meaningful. While much of this comment was directed at the requirement for periodic verification, which has since been significantly reduced, the requirement for *any* verification was criticized by many members. One member criticized the inclusion of specific time requirements governing when the record of a new customer's background information must be first sent to him for verification, claiming that such time limits are arbitrary and artificial.

Recommendation I.A.1.d. & f. (Record-Keeping). Many members criticized as unnecessarily duplicative and expensive the requirement that customer account records be kept both at headquarters and at the branch office.

Recommendation I.A.1.e. (suitability). Several firms expressed the belief that expanded concepts of suitability exposed firms to inappropriate risks of liability. Other comments were that customers should be able to make their own investment decisions without having to satisfy a third party, and that strict options suitability rules would drive customers into other, riskier, less regulated products. Specific criticism was made of the requirement that a broker must assess the customer's ability to evaluate risks, claiming that this goes beyond traditional concepts of suitability.

Recommendation I.A.1.g. (Non-sales options compliance person). This proposal drew many comments pointing out the cost it would present for small firms. The expanded exemptive provisions of the rule as filed are included in response to this concern. Some commentators objected to the concept of separating the sales function from compliance and supervision functions, while other expressed the view that the non-sales compliance officer would amount to a token appointment, but at a high cost. Many members noted that the costs of complying with this requirement would place smaller firms at a competitive disadvantage.

Recommendation I.A.1.h. (Disciplinary reports and jurisdiction). Some firms observed that a reporting requirement might inhibit firms from taking disciplinary action. Others noted the absence of clear standards defining what constitutes disciplinary action. Several commentators objected to the apparent need to file duplicate reports (which will be eliminated upon the implementation of proposed 17d–2 plans.). One comment endorsed the extension of SRO disciplinary jurisdiction over former members, while another comment expressed the view that this was improper and inconsistent with the spirit of the Act.

Recommendation I.A.1.i–l and I.A.3.a.–c. (Communications to Customers). Comments suggested that this rule imposed too many responsibilities on the CROP, that centralized approval of communications to customers is unworkable, especially in a large firm, and that advance SRO approval of advertising is contrary to the trend in such matters. Many comments were addressed to the requirements applicable to specific types of written communications, generally criticizing them for being inflexible, unworkable, expensive to administer, and enlarging the firms' exposure to liabilities.

Recommendation I.A.1.m. & n. (Allocation of exercise notices). Comments suggested that firms should be given more flexibility than this rule would permit, and that an explanation of exercise allocation would be confusing to customers. Others noted the expense involved in conforming data processing equipment to required methods of allocation.

Recommendation I.A.1.o. & p. (Market-maker's account and stock *orders)*. Many comments characterized these requirements as burdensome and costly. It was suggested that these requirements should apply to exchange floor members only, and not to upstairs traders.

Recommendation I.A.2.b. (ROP Qualification of Branch Managers). This requirement was criticized as being costly and not likely to result in improved supervision. Some suggested that it should be sufficient if an assistant manager or other supervisor is ROP-qualified, without requiring that the branch manager be so qualified.

Recommendation I.A.2.c. & d. (Discretionary Accounts). Several firms commented that these requirements would be so onerous as to inhibit firms from offering discretionary accounts. The requirement for providing an explanation of each strategy utilized in the account was the focus of special criticism. We have attempted to respond to this criticism by making the requirement apply to "programs" for trading options, but not to each separate strategy that might be used.

III. Date of Effectiveness of Proposed Rule Change and Timing for Commission Action

Within 90 days of the date of publication of this notice in the Federal Register, the Commission will:

(A) by order approve such proposed rule change, or

(B) institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views and arguments concerning the foregoing. Persons desiring to make written submissions should file 6 copies thereof with the Secretary, Securities and Exchange Commission, 500 North Capitol Street, Washington, D.C. 20549. Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule changes that are filed with the Commission, and of all written communications relating to the proposed rule changes between the commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. Section 522, will be available for inspection and copying in the Commission's Public Reference Section, 1100 L Street, N.W., Washington, D.C. Copies of such filings will also be available for inspection and copying at the principal office of the above-mentioned self-regulatory organization. All submissions should refer to file number SR-PSE-79-13 and should be submitted on or before November 2, 1979.

For the Commission, by the Division of Market Regulation, pursuant to delegated Authority.

George A. Fitzsimmons,

Secretary.

October 2, 1979.

[FR Doc. 79-31022 Filed 10-4-79; 8:45 am]

BILLING CODE 8010-01-M

[Release No. 10881; 812-4530]

Short Term Income Fund, Inc.; Filing of Application for Order of Exemption From the Provisions

September 28, 1979.

Notice is hereby given that Short Term Income Fund, Inc. ("Applicant"), 230 Park Avenue, New York, New York 10017, registered under the Investment Company Act of 1940 ("Act") as an open-end, diversified, management investment company, filed an application on September 4, 1979, and an amendment thereto on September 24, 1979, for an order pursuant to Section 6(c) of the Act, exempting Applicant from the provisions of Rules 2a-4 and 22c-1 under the Act to the extent necessary to permit Applicant to compute its price per share, for the purposes of effecting sales, redemptions and repurchases of its shares, to the nearest one cent on a share value of one dollar. All interested persons are referred to the application on file with the Commission for a statement of the representations contained therein, which are summarized below.

Applicant states that it proposes to operate as a "money market fund" designed for use by persons who maintain brokerage accounts with broker-dealers which have entered into certain account, confirmation and recordkeeping arrangements with Applicant and that its investment objective is high current income to the extent consistent with the preservation of capital and the maintenance of liquidity. According to the application, Applicant may not purchase any security which has a maturity date more than one year from the date of Applicant's purchase, unless purchased subject to a repurchase agreement calling for delivery in one year or less. In addition, Applicant represents that its portfolio may be invested in a variety of United States dollar denominated money market instruments including obligations issued or guaranteed by the United States of America, or its agencies or instrumentalities, bank time deposits, certificates of deposit, bankers' acceptances and other bank obligations, high grade commercial paper, other debt obligations if accompanied by a guarantee of principal and interest by a bank or corporation whose certificates of deposit or commercial paper are qualified for purchase by Applicant, and repurchase agreements. Applicant states that it will purchase securities with the expectation of holding them to maturity; however, Applicant also states that it may sell securities prior to maturity to meet redemptions or as a result of a revised management evaluation of the issuer.

Applicant represents that, contingent upon the granting of the requested exemption, net asset value per share will be computed for purposes of daily pricing to the nearest one percent (one cent on a per share net asset value of one dollar). Applicant states that in all other respects its portfolio securities will be valued in accordance with the views of the Commission as set forth in Investment Company Act Release No. 9786 (May 31, 1977) ("Release No. 9786").

Applicant expects that if the requested exemption permitting Applicant to round off its net asset value to the nearest one cent on a share value of one dollar is granted, then it would exclude unrealized gains and losses from its daily computation of net income. Applicant asserts that while unrealized gains and losses would be reflected in the determination of net asset value, Applicant's price per share for purposes of sales and redemptions should continue to remain constant at one dollar because of the rounding off of its computation of net asset value per share. Applicant asserts that the amounts of Applicant's daily net income dividends to shareholders would become relatively steady and consistent under its proposed pricing method because such dividends would be unaffected by fluctuations in the market prices of portfolio securities.

Applicant states that its management believes, based on experience, that these policies will benefit Applicant and its shareholders. Applicant asserts that the type of investor it seeks to attract prefers that the daily income dividents declared by Applicant reflect income as earned and that Applicant's price per share, for purposes of sales and redemptions, remain fixed. Applicant represents that its directors have determined in good faith that the stable per share value and the steady flow of investment income resulting from the foregoing policies will be helpful in attracting shareholders to Applicant and will provide a substantial benefit to such investors. Applicant states that all such investors will have the convenience of: (1) Being able to determine readily the aggregate value of their holdings simply by knowing the number of shares they own, and (2) being able to maintain investment records which do not require periodic adjustments for nominal capital gains and losses. Applicant states that at the present time it has only two directors, each of whom is affiliated with its investment adviser, and that when the full board of directors has been elected, the application, including the representations and undertakings contained therein, will be sumitted for ratification.

Rule 22c-1 under the Act provides, in part, that no registered investment company issuing any redeemable security shall sell, redeem, or repurchase any such security except at a price based on the current net asset value of such security which is next computed after receipt of a tender of such security for redemption or of an order to purchase or to sell such security. Rule 2a-4 under the Act provides, as here relevant, that "current net asset value" of a redeemable security issued by a registered investment company used in computing its price for the purposes of distribution and redemption shall be an amount which reflects calculations made substantially in accordance with the provisions of that Rule, with estimates used where necessary or appropriate. Rule 2a-4 further provides that portfolio securities for which market quotations are readily available shall be valued at current market value, and that other securities and assets shall be valued at fair value as determined in good faith by the board of directors of the registered company. In Release No. 9786, the Commission expressed its views that it is inconsistent with the provisions of Rule 2a-4 for money market funds to "round off" calculations of their net asset values per share in the manner proposed by Applicant, because such calculations might have the effect of masking the impact of changing values of portfolio securities and, therefore, net asset values per share calculated in such a manner might not "reflect" the values of portfolio securities determined as required by Rule 2a-4.

Section 6(c) of the Act provides, in part, that the Commission, upon application, may conditionally or unconditionally exempt any person, security or transaction or any class or classes of persons, securities or transactions, from any provision or provisions of the Act or of the rules thereunder, if and to the extent that such exemption is necessary or appropriate in the public interest and consistent with the protection of investors and the purposes fairly intended by the policy and provisions of the Act.

Applicant asserts that the requested exemption is appropriate in the public interest and consistent with the protection of investors and with the purposes fairly intended by the policy and provisions of the Act. Applicant states that a substantial number of money market funds now offer their shares to the public at steady prices of one dollar per share and submits that experience has shown that such funds provide a useful investment vehicle for the investors they serve. Applicant has agreed that the order it seeks may be conditioned upon ratification of the representations and undertakings contained in the application by a fully constituted board of directors, including a majority of persons who are not "interested persons" of Applicant within the meaning of Section 2(a)(19) of the Act. In addition, Applicant has agreed that, in order to attempt to assure the stability of its price per share, the order it seeks may be conditioned upon Applicant's adherence to the following conditions:

1. Applicant's Board of Directors, in supervising Applicant's operations and delegating special responsibilities involving portfolio management to Applicant's investment adviser, undertakes—as a particular responsibility within its overall duty of care owed to the shareholders of Applicant—to assure to the extent reasonably practicable, taking into account current market conditions affecting Applicant's investment objectives, that Applicant's price per share as computed for the purposes of effecting sales, redemptions and repurchases, rounded to the nearest one cent, will not deviate from one dollar.

2. Applicant will maintain a dollar-weighted average portfolio maturity appropriate to its objective of maintaining a stable price per share. Applicant will not purchase a portfolio security with a remaining maturity of greater than one year, nor will it maintain a dollar-weighted average portfolio maturity in excess of 120 days.

3. Applicant will limit its portfolio investments, including repurchase agreements, to those United States dollar denominated instruments which Applicant's Board of Directors determines present minimal credit risks, and which are of high quality as determined by any major rating service or, in the case of any instrument that is not so rated, of comparable quality as determined by Applicant's Board of Directors.

Notice is further given that any interested person may, not later than October 23, 1979, at 5:30 p.m., submit to the Commission in writing a request for a hearing on the matter accompanied by a statement as to the nature of his interest, the reason for such request, and the issues, if any, of fact or law proposed to be controverted, or he may request that he be notified if the Commission shall order a hearing thereon. Any such communication should be addressed: Secretary, Securities and Exchange Commission, Washington, D.C. 20549. A copy of such request shall be served personally or by mail upon Applicant at the address stated above. Proof of such service (by affidavit or, in case of an attorney-at-law, by certificate) shall be filed contemporaneously with the request. As provided by Rule 0-5 of the rules and regulations promulgated under the Act, an order disposing of the application will be issued as of course following said date unless the Commission thereafter orders a hearing upon request or upon the Commission's own motion. Persons who request a hearing, or advice as to whether a hearing is ordered, will receive any notices and orders issued in this matter, including the date of the hearing (if ordered) and any postponements thereof.

For the Commission, by the Division of Investment Management, pursuant to delegated authority.

George A. Fitzsimmons,

Secretary.

[FR Doc. 79-31021 Filed 10-4-79; 8:45 am]

BILLING CODE 8010-01-M

DEPARTMENT OF THE TREASURY

Fiscal Service

[Dept. Circ. 570, 1979 Rev., Supp. No. 5]

Surety Companies Acceptable On Federal Bonds

Correction

In FR Doc. 79-29703, appearing on 55264, in the issue of Tuesday, September 25, 1979, in the last column, the last line should be corrected to read: "Old San Juan, Puerto Rico, Puerto Rico 00904"

BILLING CODE 1505-01-M

Office of the Secretary

[Amdt. to Dept. Circular Public Debt Series No. 21-79]

Treasury Notes of September 30, 1981; Series X-1981

October 2, 1979.

Department of the Treasury Circular, Public Debt Series—No. 21-79, dated September 19, 1979, descriptive of Treasury Notes of Series X-1981, is hereby amended, effective September 28, 1979. The notes will be auctioned Wednesday, October 3, 1979, and will accrue interest from Tuesday, October 9, 1979.

The same numbered paragraphs of Department of the Treasury Circular, Public Debt Series—No. 21-79, are hereby amended and replaced with the following paragraphs. The other terms and conditions remain unchanged.

2. Description of Securities

2.1. The securities will be dated October 9, 1979, and will bear interest from that date, payable on a semiannual basis on March 31, 1980, and each subsequent 6 months on September 30 and March 31, until the principal becomes payable. They will mature September 30, 1981, and will not be subject to call for redemption prior to maturity.

3. Sale Procedures

3.1. Tenders will be received at Federal Reserve Banks and Branches and at the Bureau of the Public Debt, Washington, D.C. 20226, up to 1:30 p.m., Eastern Daylight Saving time, Wednesday, October 3, 1979. Noncompetitive tenders as defined below will be considered timely if postmarked no later than Tuesday, October 2, 1979.

5. Payment and Delivery

5.1. Settlement for allotted securities must be made or completed on or before Tuesday, October 9, 1979, at the Federal Reserve Bank or Branch or at the Bureau of the Public Debt, wherever the tender was submitted. Payment must be in cash; in other funds immediately available to the Treasury; in Treasury bills, notes or bonds (with all coupons detached) maturing on or before the settlement date but which are not overdue as defined in the general regulations governing United States securities; or by check drawn to the order of the institution to which the tender was submitted, which must be received at such institution no later than:

(a) Friday, October 5, 1979, if the check is drawn on a bank in the Federal Reserve District of the institution to which the check is submitted (the Fifth Federal Reserve District in case of the Bureau of the Public Debt), or

(b) Thursday, October 4, 1979, if the check is drawn on a bank in another Federal Reserve District.

Checks received after the dates set forth in the preceding sentence will not be accepted unless they are payable at the applicable Federal Reserve Bank. Payment will not be considered complete where registered securities are requested if the appropriate identifying number as required on tax returns and other documents submitted to the Internal Revenue Service (an individual's social security number or an employer identification number) is not furnished. When payment is made in securities, a cash adjustment will be made to or required of the bidder for any difference between the face amount of securities presented and the amount payable on the securities allotted.

* * * * *

The foregoing amendment was effected under authority of Section 18 and 20 of the Second Liberty Bond Act, as amended (49 Stat. 21, as amended; 31 U.S.C. 735, 754b), and 5 U.S.C. 301. Notice and public procedures thereof are unnecessary as the fiscal policy of the United States is involved.

SUPPLEMENTARY STATEMENT: The announcement set forth above does not meet the Department's criteria for significant regulations and, accordingly, may be published without compliance with the Departmental procedures applicable to such regulations.

Paul H. Taylor,
Fiscal Assistant Secretary.

[FR Doc. 79-31095 Filed 10-4-79; 8:45 am]
BILLING CODE 4810-40-M

[Admt. to Dept. Circular Public Debt Series No. 22-79]

Treasury Notes of September 30, 1983; Series F-1983

October 2, 1979.

Department of the Treasury Circular, Public Debt Series—No. 22-79, dated September 19, 1979, descriptive of Treasury Notes of Series F-1983, is hereby amended, effective September 28, 1979. The notes will be auctioned Thursday, October 4, 1979, and will accrue interest from Wednesday, October 10, 1979.

The same numbered paragraphs of Department of Treasury Circular, Public Debt Series—No. 22-79, are hereby amended and replaced with the following paragraphs. The other terms and conditions remain unchanged.

2. Description of Securities

2.1. The securities will be dated October 10, 1979, and will bear interest from that date, payable on a semiannual basis on March 31, 1980, and each subsequent 6 months on September 30 and March 31, until the principal becomes payable. They will mature September 30, 1983, and will not be subject to call for redemption prior to maturity.

3. Sale Procedures

3.1. Tenders will be received at Federal Reserve Banks and Branches and at the Bureau of the Public Debt, Washington, D.C. 20226, up to 1:30 p.m., Eastern Daylight Saving time, Thursday, October 4, 1979. Noncompetitive tenders as defined below will be considered timely if postmarked no later than Wednesday, October 3, 1979.

5. Payment and Delivery

5.1. Settlement for allotted securities must be made or completed on or before Wednesday, October 10, 1979, at the Federal Reserve Bank or Branch or at the Bureau of the Public Debt, wherever the tender was submitted. Payment must be in cash; in other funds immediately available to the Treasury; in Treasury bills, notes or bonds (with all coupons detached) maturing on or before the settlement date but which are not overdue as defined in the general regulations governing United States securities; or by check drawn to the order of the institution to which the tender was submitted, which must be received at such institution no later than:

(a) Friday, October 5, 1979, if the check is drawn on a bank in the Federal Reserve District of the institution to which the check is submitted (the Fifth Federal Reserve District in case of the Bureau of the Public Debt), or

(b) Friday, October 5, 1979, if the check is drawn on a bank in another Federal Reserve District.

Checks received after the dates set forth in the preceding sentence will not be accepted unless they are payable at the applicable Federal Reserve Bank. Payment will not be considered complete where registered securities are requested if the appropriate identifying number as required on tax returns and other documents submitted to the Internal Revenue Service (an individual's social security number or an employer identification number) is not furnished. When payment is made in securities, a cash adjustment will be made to or required of the bidder for any difference between the face amount of securities presented and the amount payable on the securities allotted.

* * * * *

The foregoing amendment was effected under authority of Section 18 and 20 of the Second Liberty Bond Act, as amended (49 Stat. 21, as amended; 31 U.S.C. 735, 754b), and 5 U.S.C. 301. Notice and public procedures thereof are unnecessary as the fiscal policy of the United States is involved.

SUPPLEMENTARY STATEMENT: The announcement set forth above does not meet the Department's criteria for significant regulations and, accordingly, may be published without compliance with the Departmental procedures applicable to such regulations.

Paul H. Taylor,

Fiscal Assistant Secretary.

[FR Doc. 79-31094 Filed 10-4-79; 8:45 am]

BILLING CODE 4810-40-M

INTERSTATE COMMERCE COMMISSION

[Notice No. 137]

Assignment of Hearings

September 28, 1979.

Cases assigned for hearing, postponement, cancellation or oral argument appear below and will be published only once. This list contains prospective assignments only and does not include cases previously assigned hearing dates. The hearings will be on the issues as presently reflected in the Official Docket of the Commission. An attempt will be made to publish notices of cancellation of hearings as promptly as possible, but interested parties should take appropriate steps to insure that they are notified of cancellation or postponements of hearings in which they are interested.

MC 129702 (Sub-5F), Carpet Transport, Inc., now assigned for hearing on December 10, 1979 (1 week), at Atlanta, GA in a hearing room to be later designated.

MC 126679 (Sub-9F), Dennis Truck Line, Inc., now assigned for hearing on December 3, 1979 (3 days), at Atlanta, GA in a hearing room to be later designated.

MC 119767 (Sub-349F), Beaver Transport Co., A Corp., transferred to modified procedure.

MC 115311 (Sub-307), J & M TRANSPORTATION CO., INC., now assigned for hearing December 4, 1979, at New Orleans, La. will be held at Monteleone Motel, 214 Royale Street.

MC 145838 (Sub-1F), Ohio Container Service, Inc., now assigned for hearing on October 3, 1979 is postponed to November 14, 1979 (3 days), at Cleveland, OH in a hearing room to be later designated.

MC 125156 (Sub-2F), Dawson's Charter Servicde, Inc., now assigned for hearing on October 10, 1979, at Washington, D.C. is postponed indefinitely.

MC 115322 (Sub-162F), Redwing Refrigerated, Inc., transfered to Modified Procedure.

MC 144513 (Sub-4F), Matco Transportation, Inc., transfered to Modified Procedure.

MC 123048 (Sub-429F), Diamond Transportation System, Inc., transfered to Modified Procedure.

MC 116763 (Sub-486F), Carl Subler Trucking, Inc., transfered to Modified Procedure.

MC 112304 (Sub-169F), Ace Doran Hauling & Rigging Co., a corporation, now being assigned for hearing on November 27, 1979 (1 Day), at Kansas City, KS. in a hearing room to be designated later.

MC 117815 (Sub-289F), Pulley Freight Lines, Inc., now being assigned for hearing on November 28, 1979 (3 Days), at Kansas City, KS. in a hearing room to be designated later.

MC 146038 (Sub-1F), Quick Silver, Inc., now being assigned for hearing on December 3, 1979 (1 Week), at Kansas City, KS. in a hearing room to be designated later.

MC 67866 (Sub-36F), Film Transit, Inc., now assigned for hearing on October 30, 1979, at Little Rock, Arkansas is postponed indefinitely.

MC 64832 (Sub-7F), Magnolia Truck Lines, Inc., now assigned for hearing on October 30, 1979 (9 days), at Memphis, TN will be held in Room No. 435, Federal Building 167 North Main.

MC 109533 (Sub-105F), Overnite Transportation Company, now assigned for hearing on October 23, 1979 (9 days), at Atlanta, GA will be held in Riviera Hyatt House, 1630 Peachtree Street, N.W.

MC 135812 (Sub-1F), Professional Driver Service, Inc., and MC-140245, Professional Driver Services, Inc., Contract Carrier Application, now assigned for hearing on November 6, 1979 (4 days) at Nashville, TN location of hearing room will be designated later.

MC 98187 (Sub-3), Frederick M. Jacobs, D/B/A Waldron Truck Lines, now assigned for hearing on October 15, 1979 (1 week), at Fort Smith, AR will be held in the GSA Conference, Room 213, U.S. Post Office & Courthouse, South 6th & Roger.

MC 139571 (Sub-1F), A. S. Madison, Inc., now assigned for hearing on December 5, 1979 (3 days), at Bakersfield, CA in a hearing room to be later designated.

MC 98689 (Sub-2F), D. A. Brown Trucking Co., now assigned for hearing on December 10, 1979 (1 week), at Bakersfield, CA in a hearing room to be later designated.

AB 43 (Sub-45), Illinois Central Gulf Railroad Company Abandonment at Rio, Louisiana and Lexie, Mississippi in Washington Parish, Louisiana, and Walthal County, Mississippi now being assigned for continued hearing on November 7, 1979 (3 Days) at Chicago IL, in a hearing room to be designated later.

MC 113666 (Sub-151F), Freeport Transport, Inc., now being assigned for hearing on November 28, 1979 (1 Day) at Pittsburgh, PA, in a hearing room to be designated later.

MC 123091 (Sub-29F), Nick Strimbu, Inc., now being assigned for hearing on November 29, 1979 (2 Days) at Pittsburgh, PA, in a hearing room to be designated later.

MC 123255 (Sub-186F), B&L Motor Freight, Inc., now being assigned for hearing on December 3, 1979 (1 Week) at Columbus, OH. in a hearing room to be designated later.

MC 121664 (Sub-54F), Hornady Truck Line, now being assigned for hearing on November 26, 1979 (3 Days) at Montgomery, AL. in a hearing room to be designated later.

I & S 8863 Switching and Minimum Carload Charges, Houston Texas, now being assigned for continued hearing on November 5, 1979, at the Offices of the Interstate Commerce Commission, Washington, D.C.

AB-6-(Sub-60F), Burlington Northern, Inc. Abandonment Near St. Joseph, MO, And Humeston, IA, in Buchanan, Andrew, Dekalb, Gentry and Harrison Counties, MO And Decatur And Wayne Counties, IA, now assigned for hearing on October 15, 1979 at Bethany, MO is postponed to November 27, 1979 (3 days) at Bethany, MO in a hearing room to be later designated.

MC 100666 (Sub-432F), Melton Truck Lines, Inc, transferred to Modified Procedure.

MC 108382 (Sub-32F), Short Freight Lines, Inc., transfered to Modified Procedure.

MC 136511 (Sub-25F), Virginia Appalachian Lumber Corporation, transfered to Modified Procedure.

MC 127840 (Sub-84F), Montgomery Tank Lines, Inc., now assigned for continued hearing on October 16, 1979 (4 days), at Chicago, IL will be held in Room 1530, OSHRC, 55 East Monroe Street.

Agatha L. Mergenovich,

Secretary.

[FR Doc. 79-31001 Filed 10-4-79; 8:45 am]

BILLING CODE 7035-01-M

[Emergency Service Order 1398; Supplemental Order No. 1]

Kansas City Terminal Railway Co.—Directed to Operate Over—Chicago, Rock Island & Pacific Railroad Co., Debtor (William M. Gibbons, Trustee)

October 1, 1979.

On September 26, 1979, the Interstate Commerce Commission, pursuant to 49 U.S.C. 11125, directed the Kansas City Terminal Railway Company ("KCT") to provide service for traffic originating or terminating on the lines of the Chicago, Rock Island & Pacific Railroad Company, Debtor (William M. Gibbons, Trustee) ("RI") (44 FR 56343, Oct. 1, 1979).

The directed-service order was predicated upon the RI's inability to transport the traffic offered to it due to a cash position which makes its continuing operation impossible, within the meaning of 49 U.S.C. 11125(a)(1).

The Kansas City Terminal Railway Company, the directed rail carrier ("DRC"), believes that for it to begin operations it is essential to clarify the definition of the liabilities and expenses to be treated as compensable costs, especially in view of the probable unavailability of insurance to cover the many areas of exposure to which the DRC will be subject.

Accordingly, the first paragraph under the heading "Liabilities and Expenses," on page 26 of the Directed Service Order should be construed to, and is hereby revised to include the following:

We shall treat as compensable costs of directed service all liabilities and expenses, including reasonable attorneys' fees and costs of litigation, arising out of directed service operation, including but not limited to all claims, actions and liabilities (I) Arising out of wrecks or derailments; (II) For injury to or death of any person, including claims or actions arising under the Federal Employers Liability Act; (III) Damage to or destruction or deterioration of property, on or arising from operation of directed services lines, including lading, cars, locomotives, material, supplies, fuel, equipment, rail lines and facilities; and (IV) Against officers or directors of the DRC, or against personnel of the DRC's management team, for acts, errors or omissions in connection with the performance of directed service.

By the Commission, Chairman O'Neal, Vice Chairman Stafford, Commissioners Gresham, Clapp, Christian, Trantum, Gaskins, and Alexis. Chairman O'Neal and Commissioner Gresham were absent and did not participate.

Agatha L. Mergenovich,

Secretary.

[FR Doc. 79-30995 Filed 10-4-79; 8:45 am]

BILLING CODE 7035-01-M

[Exemption No. 169 to Amendment No. 1]

Exemption Under Provision of Rule 19 of the Mandatory Car Service Rules Ordered in Ex Parte No. 241

To: All Railroads. Upon further consideration of Exemption No. 169 issued July 25, 1979.

It is ordered, That, under authority vested in me by Car Service Rule 19, Exemption No. 169 to the Mandatory Car Service Rules ordered in Ex Parte No. 241 is amended to expire October 31, 1979.

This amendment shall become effective September 30, 1979.

Issued at Washington, D.C., September 26, 1979.

Interstate Commerce Commission.

Joel E. Burns,

Agent.

[FR Doc. 79-30998 Filed 10-4-79; 8:45 am]

BILLING CODE 7035-01-M

[Amendment No. 2 to Revised Exemption No. 171]

Exemption Under Provision of Rule 19 of the Mandatory Car Service Rules Ordered in Ex Parte No. 241

TO: All Railroads. Upon further consideration of Revised Exemption No. 171 issued August 30, 1979.

It is ordered, That, under authority vested in me by Car Service Rule 19, Revised Exemption No. 171 to the Mandatory Car Service Rules ordered in Ex Parte No. 241 is amended to expire September 28, 1979.

This amendment shall become effective September 14, 1979.

Issued at Washington, D.C., September 12, 1979.

Interstate Commerce Commission.

Joel E. Burns,

Agent.

[FR Doc. 79-30997 Filed 10-4-79; 8:45 am]

BILLING CODE 7035-01-M

[Thirty-Second Revised Exemption No. 129]

Exemption Under Provision of Rule 19 of the Mandatory Car Service Rules Ordered in Ex Parte No. 241

It appearing, That the railroads named herein own numerous forty-foot plain boxcars; that under present conditions, there is virtually no demand for these cars on the lines of the car owners; that return of these cars to the car owners would result in their being stored idle on these lines; that such cars can be used by other carriers for transporting traffic offered for shipments to points remote from the car owners; and that compliance with Car Service Rules 1 and 2 prevents such use of plain boxcars owned by the railroads listed herein, resulting in unnecessary loss of utilization of such cars.

It is ordered, That, pursuant to the authority vested in me by Car Service Rule 19, plain boxcars described in the Official Railway Equipment Register, ICC RER 6410-B, issued by W. J. Trezise, or successive issues thereof, as having mechanical designation "XM," with inside length 44-ft. 6-in. or less, regardless of door width and bearing reporting marks assigned to the railroads named below, shall be exempt from provisions of Car Service Rules 1(a), 2(a), and 2(b).

Atlanta & Saint Andrews Bay Railway Company Reporting Marks: ASAB
Chicago, West Pullman & Southern Railroad Company Reporting Marks: CWP
Illinois Terminal Railroad Company Reporting Marks: ITC
Louisville, New Albany & Corydon Railroad Company Reporting Marks: LNAC
New Hope and Ivyland Railroad Company Reporting Marks: NHIR
North Stratford Railroad Corporation Reporting Marks: NSRC
*Southern Pacific Transportation Company Reporting Marks: SP

Effective September 15, 1979, and continuing in effect until further order of this Commission.

Issued at Washington, D.C., September 12, 1979.

Interstate Commerce Commission.

Joel E. Burns,

Agent.

[FR Doc. 79-31000 Filed 10-4-79; 8:45 am]

BILLING CODE 7035-01-M

[Service Order No. 1344; I.C.C. Order No. 52]

Rerouting Traffic

To all railroads: In the opinion of Joel E. Burns, Agent, The Baltimore and Ohio Railroad Company (B&O) is unable to transfer shipments of coal from rail to water at its coal unloading piers at Curtis Bay, Baltimore, Maryland, because of damage to the ship loader machinery.

It is ordered: (a) The B&O being unable to transfer shipments of coal from rail to water at its coal unloading piers at Curtis Bay, Baltimore, Maryland, because of damage to the ship loader machinery is hereby authorized to divert such traffic to Newport News, Virginia, via any available route, for unloading at the coal piers located at that point. Traffic necessarily diverted by authority of this order shall be rerouted so as to preserve as nearly as possible the participation and revenues of other carriers provided in the original routing. The billing covering all such cars diverted shall carry a reference to the order as authority for the diversion.

(b) *Concurrence of receiving roads to be obtained.* The B&O, when diverting traffic in accordance with this order, shall receive the concurrence of other railroads to which such traffic is to be diverted before the diversion is ordered.

(c) *Notification to shippers.* The B&O, when diverting cars in accordance with this order, shall notify each shipper at the time each car is diverted and shall furnish to such shipper the new routing provided for under this order.

(d) Inasmuch as the diversion of traffic is deemed to be due to carrier disability, the rates applicable to traffic diverted by said Agent shall be the rates which were applicable at the time of shipment on the shipments as originally routed.

*Addition

(e) In executing the directions of the Commission and of such Agent provided for in this order, the common carriers involved shall proceed even though no contracts, agreements or arrangements now exist between them with reference to the divisions of the rates of transportation applicable to said traffic. Divisions shall be, during the time this order remains in force, those voluntarily agreed upon by and between said carriers; or upon failure of the carriers to so agree, said division shall be those hereafter fixed by the Commission in accordance with pertinent authority conferred upon it by the Interstate Commerce Act.

(f) *Effective date.* This order shall become effective at 4 p.m., September 14, 1979.

(g) *Expiration date.* This order shall remain in effect until modified or vacated by order of this Commission.

This order shall be served upon the Association of American Railroads, Car Service Division, as agent of all railroads subscribing to the car service and car hire agreement under the terms of that agreement, and upon the American Short Line Railroad Association. A copy of the order shall be filed with the Director, Office of the Federal Register.

Issued at Washington, D.C., September 14, 1979.

Interstate Commerce Commission.

Joel E. Burns,

Agent.

[FR Doc. 79-30999 Filed 10-4-79; 8:45 am]

BILLING CODE 7035-01-M

[Fourth Revised Exemption No. 141]

Exemption Under Provision of Rule 19 of the Mandatory Car Service Rules Ordered in Ex Parte No. 241

To All Railroads: It appearing, That the railroads named below own numerous plain gondola cars less than 61-ft.; that under present conditions there are surpluses of these cars on their lines; that return of these cards to the owner would result in their being stored idle; that such cars can be used by other carriers for transporting traffic offered for shipments to points remote from the car owner; and that compliance with Car Service Rules 1 and 2 prevents such use of these cars, resulting in unnecessary loss of utilization of such cars.

It is ordered, That pursuant to the authority vested in me by Car Service Rule 19, plain gondola cars, less than 61-ft. in length, described in the Official Railway Equipment Register, ICC RER No. 6410-B, issued by W. J. Trezise, or successive issues thereof, as having mechanical designation "GB", which are less than 61-ft. in length, and which bear the reporting marks listed below, may be used without regard to the requirements of Car Service Rules 1 and 2.

Chicago, West Pullman & Southern Railroad Company
Reporting Marks: CWP-CWP&S
*East St. Louis Junction Railroad Company
Reporting Marks: ESLJ
Louisiana Midland Railway Company
Reporting Marks: LOAM
*Maryland and Delaware Railroad Company
Reporting Marks: MDDE

Effective September 15, 1979, and continuing in effect until further order of this Commission.

Issued at Washington, D.C., September 12, 1979.

Interstate Commerce Commission.

Joel E. Burns,

Agent.

[FR Doc. 79-30996 Filed 10-4-79; 8:45 am]

BILLING CODE 7035-01-M

*Additions.

[No. MC-C-9873]

Interpretation of Aggregated Commodities Service Classification

AGENCY: Interstate Commerce Commission.

ACTION: Final Commodity Interpretation.

SUMMARY: The commodity description "commodities, the transportation of which requires special equipment because of size or weight," or similarly framed commodity descriptions, commonly referred to as "heavy-hauler" authority, interpreted. Interpretative standards established for such authority as it relates to the transportation of aggregated commodities. This action clarifies the scope of the heavy-haulers' authority to handle shipments of aggregated commodities.

EFFECTIVE DATE: Sixty days after the date of publication of this notice in the Federal Register.

FOR FURTHER INFORMATION CONTACT: Donald J. Shaw, Jr., (202) 275-7292.

FOR COPIES OF THIS NOTICE CONTACT: Office of the Secretary, Interstate Commerce Commission, Washington, D.C. 20423.

SUPPLEMENTAL INFORMATION: This proceeding arises from a petition for declaratory order described at 42 FR 62997 (December 14, 1977). After receiving comments from the public concerning this petition, the Commission issued a notice of proposed commodity interpretation described at 43 FR 32346 (July 26, 1978). The Commission in that notice indicated its intent to interpret the commodity description "commodities, the transportation of which requires special equipment because of size or weight," or similarly framed commodity descriptions (commonly referred to as "heavy-hauler" authority), insofar as it relates to the transportation of aggregated commodities traffic.

Representations from the public concerning industry shipping practices, shipper service requirements, and the extent of participation by heavy haulers and other carriers in aggregated commodities traffic were solicited. Interested parties were requested to comment upon each of two proposed interpretative options. In this decision, the Commission formally adopts two commodity interpretations describing the permissible extent of heavy-hauler participation in aggregated commodities traffic.

In the first interpretation, the Commission reaffirmed the presumption established in *W. J. Dillner Transfer Co.—Investigation of Operations,* 79 M.C.C. 335 (1959), that shipments of aggregated commodities, in the absence of a sound basis for a contrary conclusion, are outside the scope of heavy-hauler authority. However, in future determinations as to whether this presumption has been overcome, the criteria enumerated in *Ace Doran Hauling & Rigging Co. Investigation,* 108 M.C.C. 717 (1969) will be considered in balance. The basic characteristics of the commodity—the first *Ace Doran* criterion will no longer be afforded threshold status, and the "inherent nature" test articulated in *Dillner* need no longer be considered other than as part of the first criterion in the four-part *Ace Doran* test.

The Commission indicated its intent to allow greater latitude in determining whether the use of special equipment is "required" in the transportation of shipments of aggregated commodities, and emphasized the importance of the second *Ace Doran* criterion—prevailing industry shipping practices. Finally, the continuing importance of the fourth *Ace Doran* criterion—traditional sphere of carriage (field of service) was emphasized. The Commission indicated that awareness of this guideline will generally operate to prevent heavy haulers from handling commodities in those fields of service that have traditionally been beyond their reach.

In the second interpretation, the Commission determined that heavy haulers would be considered authorized to transport aggregated shipments of metal, metal products, and pipe, provided that special equipment is used for their loading, unloading, or over-the-road transportation. This interpretation applies regardless of the method of aggregation used. Where the manner of aggregation is such that the contents of the bundle are not readily ascertainable by physical examination, the carrier has an affirmative duty to determine that the contents consist of commodities included within the meaning of this interpretation. The fact that a shipper may provide the special equipment for loading, unloading, or movement of the traffic does not preclude the application of this interpretation. The Commission modified the original proposal by deleting an additional requirement that each aggregated bundle tendered for shipment either weigh at least 200 pounds or have an exterior dimension of at least 40 feet in length. In making this modification, the Commission reasoned that this requirement was unnecessary to the objectives of the proceeding.

The Commission stated that none of the interpretative guidelines provided would apply to intermodal shipments in marine, rail, air or similar cargo containers. These intermodal operations have generally been held to be beyond the scope of heavy-hauler authority.

The described interpretations were found to be consistent with Commission policy and the language of the involved commodity description.

Adopted under authority of 5 U.S.C. 554 and 49 U.S.C. 10321 (formerly section 204 of the Interstate Commerce Act.)

Dated: September 26, 1979.

By the Commission, Chairman O'Neal, Vice Chairman Stafford, Commissioners Gresham, Clapp, Christian, Trantum, Gaskins and Alexis. Vice Chairman Stafford dissenting in part and concurring in part.

Commissioner Alexis did not participate in the disposition of this proceeding.

Agatha L. Mergenovich,

Secretary.

Commissioner Stafford, dissenting in part; concurring in part:

I concur with the majority's finding that the presumption described in the *Dillner* case, *supra,* should be reaffirmed without modification. I further agree that intermodal shipments should not be considered shipments of aggregated commodities and accordingly the new guidelines should not apply to them. Finally, I agree that the interpretation of "size and weight" authority, herein adopted, should not be applied to alter existing interpretations of authorities which usually are restricted against the transportation of "size and weight" traffic.

In all other respects, I disagree with the majority's conclusions. For one, I have not *frequently* encountered the question of whether an aggregated-commodities shipment requires the use of special equipment. (See pg. 2.) Indeed, I cannot recall a proceeding—at the Commission level—involving heavy hauler interpretation in recent memory. Consequently, I question the need to redefine longstanding Commission policy as set forth in *Ace Doran* and related cases. The whole reason why we entered into this lengthy proceeding with its commensurate costs to interested parties frankly puzzles me. Ironically, the "re-balancing" of the *Doran* criteria only sets the stage for new proceedings. This is so because of the inherent vagueness of exactly what the majority desires to "re-balance".

Assuming there is a need for this proceeding, a reading of the decisions underlying rationale leads to one inescapeable conclusion: Heavy haulers will infringe on traffic now handled by general commodity haulers with no counteracting benefit to general commodity haulers. Even from the shipper's standpoint the long-term benefits of such "liberalization" or "additional service" are far from clear. I for one envision the heavy haulers selectively taking desirable shipments, particularly from large shippers, at the expense of the shipper needing a truly responsive common carrier.

[FR Doc. 79-31002 Filed 10-4-79; 8:45 am]
BILLING CODE 7035-01-M

Sunshine Act Meetings

Federal Register
Vol. 44, No. 195
Friday, October 5, 1979

This section of the FEDERAL REGISTER contains notices of meetings published under the "Government in the Sunshine Act" (Pub. L. 94-409) 5 U.S.C. 552b(e)(3).

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[M-250, Amdt. 1; Oct. 2, 1979]

CIVIL AERONAUTICS BOARD.

Notice of deletion of item from the October 4, 1979 meeting.

TIME AND DATE: 9:30 a.m., October 4, 1979.

PLACE: Room 1027, 1825 Connecticut Avenue NW., Washington, D.C. 20428.

SUBJECT: 9a. Docket 34681, Request for instructions on Carrier Selection, Upstate New York Case. (BDA, OGC, OEA)

STATUS: Open.

PERSON TO CONTACT: Phyllis T. Kaylor, the Secretary, (202) 673-5068.

SUPPLEMENTARY INFORMATION: In order to permit sufficient advance notice for all of the interested parties, including the communities affected by this case, who may wish to attend, the staff request that this item be moved to the October 9, 1979 calendar meeting. Accordingly, the following Members have voted that Item 9a be deleted from the October 4, 1979 agenda and that no earlier announcement of this deletion was possible:

Chairman, Marvin S. Cohen
Member, Richard J. O'Melia
Member, Elizabeth E. Bailey
Member, Gloria Schaffer

[S-1939-79 Filed 10-3-79; 3:36 pm]
BILLING CODE 6320-01-M

2

[M-251, Oct. 2, 1979]

CIVIL AERONAUTICS BOARD.

TIME AND DATE: 9:30 a.m., October 9, 1979.

PLACE: Room 1027, 1825 Connecticut Avenue, N.W., Washington, D.C. 20428.

SUBJECT:

1. Ratification of items adopted by notation.
2. Dockets 33283 and 33112, Pan American-TXI Merger. (OGC)
3. Docket 30399, *Oakland Service Case (Economic Phase)*, Opinion and Order. (OGC)
4. Docket 32381, *Spokane-Vancouver Route Proceeding* Petition for Reconsideration of Western Air Lines. (OGC)
5. Dockets 35658, 35826, 35827, 25832, 35818, 35843, 35828, 35830, and 35809; *Boston/Philadelphia/Pittsburgh-Tampa Show Cause Proceeding;* New applications of Air New England, American, Ozark, Piedmont, Republic, and Trans World for this authority. Braniff requests Boston-Tampa authority while Northwest requests Pittsburgh-Tampa authority. (BDA)
6. Docket 34725, *Southwest Alaska Service Investigation,* application of Klondike Air, Inc., for a certificate. (BDA)
7. Docket 32398, Supplemental Fill-Up Case. (OGC)
8. Dockets 35274 and 35268, *World Airways, Inc., Enforcement Proceeding.* (OGC)
9. Criteria for designating additional eligible points. (OGC, BDA)
10. Docket 34774, Motion filed by Air Central protesting Order 79-8-53, in Docket 34774. (BDA, OCCR)
11. Docket 34681, Request for instructions on Carrier Selection, Upstate New York Case. (BDA, OGC, OEA)
12. Dockets 36594 and 36651, Aspen Airways' notice of intent to terminate service at Gunnison, CO; Aspen Airways' application for exemption from section 401(j) of the Act. (BDA, OCCR)
13. Dockets 36456, 36493, and 36509; 30-day notice of Air Illinois of intent to terminate service at Kirksville, MO; 90- and 60-day notices of Ozark Air Lines of intent to terminate service at Kirksville. (BDA, OCCR)
14. Docket 36147, USAir's application for certificate authority under Subpart Q for Salt Lake City-Houston/Burbank authority. (Memo #9187, BDA)
15. Agreement CAB 27337, *et al.,* Agreements for intercarrier division of joint fares. (BDA)
16. Docket 32484, Finalization of Class Rate IX. (BDA, OCCR, OGC, OC)
17. Air New England, Inc., violations of Part 250. (BCP)

STATUS: Open.

PERSON TO CONTACT: Phyllis T. Kaylor, the Secretary, (202) 673-5068.

[S-1940-79 Filed 10-3-79; 3:36 pm]
BILLING CODE 6320-01-M

3

EQUAL EMPLOYMENT OPPORTUNITY COMMISSION.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: S-1868-79.

PREVIOUSLY ANNOUNCED TIME AND DATE OF MEETING: 9:30 a.m. (Eastern Time), Tuesday, September 25, 1979.

CHANGE IN THE MEETING: The following matter was added to the agenda for the open portion of the meeting:

Temporary delegation of certain procurement authority to the General Counsel.

A majority of the entire membership of the Commission determined by recorded vote that the business of the Commission required this change and that no early announcement was possible.

In favor of change: Eleanor Holmes Norton, Chair; Daniel E. Leach, Vice Chair; Ethel Bent Walsh, Commissioner; Armando M. Rodriguez, Commissioner.

CONTACT PERSON FOR MORE INFORMATION: Marie D. Wilson, Executive Officer, Executive Secretariat, at (202) 634-6748.

This notice issued September 25, 1979.

[S-1914-79 Filed 10-3-79; 3:33 pm]
BILLING CODE 6570-06-M

4

EQUAL EMPLOYMENT OPPORTUNITY COMMISSION.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: S-1894-79.

PREVIOUSLY ANNOUNCED TIME AND DATE OF MEETING: 9:30 a.m. (Eastern Time), Friday, September 28, 1979.

CHANGE IN THE MEETING: The following matter was added to the agenda for the open portion of the meeting:

Questions and Answers under the Pregnancy Discrimination Act.

A majority of the entire membership of the Commission determined by recorded vote that the business of the Commission required this change and that no earlier announcement was possible.

In favor of change: Eleanor Holmes Norton, Chair; Daniel E. Leach, Vice Chair; Ethel Bent Walsh, Commissioner.

CONTACT PERSON FOR MORE INFORMATION: Marie D. Wilson, Executive Officer, Executive Secretariat, at (202) 634-6748.

This notice issued September 26, 1979.

[S-1915-79 Filed 10-3-79; 3:36 pm]
BILLING CODE 6570-06-M

5

EQUAL EMPLOYMENT OPPORTUNITY COMMISSION.

TIME AND DATE: 9:30 a.m. Tuesday, October 2, 1979.

PLACE: Commission Conference Room, 5240, on the fifth floor of the Columbia Plaza Office Building, 2401 E Street NW., Washington, D.C. 20506.

MATTERS TO BE CONSIDERED:

1. Proposed regulations on Nondiscrimination on the Basis of Age in Programs or Activities receiving Federal Financial Assistance from EEOC.
2. Report on Commission Operations by the Executive Director.

CLOSED TO THE PUBLIC:

1. Litigation authorization; General Counsel Recommendations.
2. Discussion of investigative strategy.

Note.—Any matter not discussed or concluded may be carried over to a later meeting.

CONTACT PERSON FOR MORE INFORMATION: Marie D. Wilson, Executive Officer, Executive Secretariat, at (202) 634-6748.

This notice issued September 26, 1979.

[S-1916-79 Filed 10-3-79; 3:36 pm]

BILLING CODE 6570-06-M

6

FEDERAL ELECTION COMMISSION.

DATE AND TIME: Wednesday, October 10, 1979 at 10 a.m.

PLACE: 1325 K Street NW., Washington, D.C.

STATUS: This meeting will be closed to the public.

MATTERS TO BE DISCUSSED: Compliance and personnel.

DATE AND TIME: Thursday, October 11, 1979 at 10 a.m.

PLACE: 1325 K Street NW., Washington, D.C.

STATUS: This meeting will be open to the public.

MATTERS TO BE DISCUSSED:

Setting of dates for future meetings.
Correction and approval of minutes.
Advisory opinion 1979-48: James S. Eastham (Rexnord Inc. PAC).
Reports on financial activity—Primary matching fund.
1980 elections and related matters.
Consultant's report on audit process (continued).
Ernst & Whinny Consultant's report on statistical sampling—certification process.
Appropriations and budget.
Pending legislation.
Classification actions.
Routine administrative matters.

PERSON TO CONTACT FOR INFORMATION: Mr. Fred Eiland, Public Information Officer. Telephone: 202-523-4065.

Lena L. Stafford,

Acting Secretary to the Commission.

[S-1936-79 Filed 10-3-79; 3:00 pm]

BILLING CODE 6715-01-M

7

FEDERAL ENERGY REGULATORY COMMISSION.

TIME AND DATE: October 5, 1979, 10 a.m.

PLACE: 825 North Capitol Street NE., Washington, D.C. 20426, Room 9306.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Recommended action related to a formal private investigation.

CONTACT PERSON FOR MORE INFORMATION: Kenneth F. Plumb, Secretary, Telephone: (202) 357-8400.

[S-1941-79 Filed 10-3-79; 3:42 pm]

BILLING CODE 6450-01-M

8

FEDERAL HOME LOAN BANK BOARD.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: Vol. 44, FR Page 56452. October 1, 1979.

PREVIOUSLY ANNOUNCED TIME AND DATE OF MEETING: 9:30 a.m., October 4, 1979.

PLACE: 1700 G Street NW., Sixth Floor, Washington, D.C.

STATUS: Open Meeting.

CONTACT PERSON FOR MORE INFORMATION: Franklin O. Bolling, (202-377-6677).

CHANGES IN THE MEETING: The following item was added to the agenda for the open meeting.

Regulation on Extension of Comment Period on Washington SMSA Branching.

No. 274, October 3, 1979.

[S-1937-79 Filed 10-3-79; 3:00 pm]

BILLING CODE 6720-01-M

9

FEDERAL RESERVE SYSTEM (BOARD OF GOVERNORS).

TIME AND DATE: 10 a.m., Wednesday, October 10, 1979.

PLACE: 20th Street and Constitution Avenue NW., Washington, D.C. 20551.

STATUS: Open.

MATTERS TO BE CONSIDERED:

Summary Agenda

Because of their routine nature, no substantive discussion of the following items is anticipated. These matters will be resolved with a single vote unless a member of the Board requests that an item be moved to the discussion agenda.

1. Proposed collection of data through:
(a) a Survey of Finance Companies;
(b) a new Report of Selected Borrowings (FR 2415);
(c) a report on credit union deposits;
(d) a report on outstanding travelers checks; and
(e) a report on money market mutual funds.
2. Proposed policy statement on discrimination by financial institutions.

Discussion Agenda

1. Proposed amendments to the Interagency Uniform Guidelines for Enforcement of Regulation 2 (Truth in Lending).
2. Proposed statement to be presented to the Consumer Affairs Subcommittee of the Senate Committee on Banking, Housing, and Urban Affairs regarding Truth-in-Lending enforcement policies.
3. Any agenda items carried forward from a previously announced meeting.

Note.—This meeting will be recorded for the benefit of those unable to attend. Cassettes will be available for listening in the Board's Freedom of Information Office, and copies may be ordered for $5 per cassette by calling (202) 452-3684 or by writing to: Freedom of Information Office, Board of Governors of the Federal Reserve System, Washington, D.C. 20551.

CONTACT PERSON FOR MORE INFORMATION: Mr. Joseph R. Coyne, Assistant to the Board, (202) 452-3204.

Dated: October 2, 1979.

Griffith L. Garwood,

Deputy Secretary of the Board.

[S-1934-79 Filed 10-3-79; 10:36 pm]

BILLING CODE 6210-01-M

10

NATIONAL TRANSPORTATION SAFETY BOARD.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: S-1927-79, to be published October 4, 1979.

PREVIOUSLY ANNOUNCED TIME AND DATE OF MEETING: Thursday, October 4, 1979, 9 a.m. [NM-79-35].

CHANGE IN MEETING: This meeting was scheduled in error.

CONTACT PERSON FOR MORE INFORMATION: Sharon Flemming, 202-472-6022.

October 3, 1979.

[S-1938-79 Filed 10-3-79; 3:36 pm]

BILLING CODE 4910-58-M

11

PAROLE COMMISSION: National Commissioners (the Commissioners presently maintaining offices at Washington, D.C. Headquarters).

TIME AND DATE: Thursday, October 18, 1979 at 9:30 a.m.

PLACE: Room 828, 320 First Street NW., Washington, D.C. 20537.

STATUS: Closed pursuant to a vote to be taken at the beginning of the meeting.

MATTERS TO BE CONSIDERED: Referrals from Regional Commissioners of approximately 15 cases in which inmates of Federal prisons have applied for parole or are contesting revocation of parole or mandatory release.

CONTACT PERSON FOR MORE INFORMATION: A. Ronald Peterson, Analyst: (202) 724–3094.

[S-1937-79 Filed 10-3-79; 11:15 am]
BILLING CODE 4410-01-M

Reader Aids

Federal Register
Vol. 44, No. 195
Friday, October 5, 1979

INFORMATION AND ASSISTANCE

Questions and requests for specific information may be directed to the following numbers. General inquiries may be made by dialing 202-523-5240.

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275-3030	Slip Law Orders (GPO)

Other Publications and Services:

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AGENCY PUBLICATION ON ASSIGNED DAYS OF THE WEEK

The following agencies have agreed to publish all documents on two assigned days of the week (Monday/Thursday or Tuesday/Friday).

This is a voluntary program. (See OFR NOTICE FR 32914, August 6, 1976.)

Monday	Tuesday	Wednesday	Thursday	Friday
DOT/SECRETARY*	USDA/ASCS		DOT/SECRETARY*	USDA/ASCS
DOT/COAST GUARD	USDA/APHIS		DOT/COAST GUARD	USDA/APHIS
DOT/FAA	USDA/FNS		DOT/FAA	USDA/FNS
DOT/FHWA	USDA/FSQS		DOT/FHWA	USDA/FSQS
DOT/FRA	USDA/REA		DOT/FRA	USDA/REA
DOT/NHTSA	MSPB/OPM		DOT/NHTSA	MSPB/OPM
DOT/RSPA	LABOR		DOT/RSPA	LABOR
DOT/SLSDC	HEW/FDA		DOT/SLSDC	HEW/FDA
DOT/UMTA			DOT/UMTA	
CSA			CSA	

Documents normally scheduled for publication on a day that will be a Federal holiday will be published the next work day following the holiday.

Comments on this program are still invited. Comments should be submitted to the Day-of-the-Week Program Coordinator. Office of the Federal Register, National Archives and Records Service, General Services Administration, Washington, D.C. 20408

***NOTE: As of July 2, 1979, all agencies in the Department of Transportation, will publish on the Monday/Thursday schedule.**

REMINDERS

The items in this list were editorially compiled as an aid to **Federal Register** users. Inclusion or exclusion from this list has no legal significance. Since this list is intended as a reminder, it does not include effective dates that occur within 14 days of publication.

Rules Going Into Effect Today

Note: There were no items eligible for inclusion in the list of Rules Going Into Effect Today.

HOUSING AND URBAN DEVELOPMENT DEPARTMENT

Federal Housing Commissioner—Office of Assistant Secretary for Housing—

51800 9-5-79 / Rental projects; eligibility requirements for mortgage insurance

Office of Assistant Secretary for Community Planning and Development—

51160 8-30-79 / Community Development Block Grants; loan guarantees

INTERIOR DEPARTMENT

Land Management Bureau—

52686 9-10-79 / Idaho; partial revocation of phosphate reserve nos. 2, 13, 19, and 31

• [Corrected at 44 FR 54299, 9-19-79]

52685 9-10-79 / Partial revocation of PLO 5682

INTERSTATE COMMERCE COMMISSION

24290 4-25-79 / Tariffs and schedules: Motor vehicle property contract carriers; looseleaf schedules

TREASURY DEPARTMENT

Comptroller of the Currency—

51795 9-5-79 / Loans secured by real estate; interpretive rulings

List of Public Laws

Note: No public bills which have become law were received by the Office of the Federal Register for inclusion in today's List of Public Laws.

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Part II

Department of Labor

Employment Standards Administration

Minimum Wages for Federal and Federally Assisted Construction; General Wage Determination Decisions

DEPARTMENT OF LABOR

Employment Standards Administration, Wage and Hour Division

Minimum Wages for Federal and Federally Assisted Construction

General Wage Determination Decisions

General wage determination decisions of the Secretary of Labor specify, in accordance with applicable law and on the basis of information available to the Department of Labor from its study of local wage conditions and from other sources, the basic hourly wage rates and fringe benefit payments which are determined to be prevailing for the described classes of laborers and mechanics employed on construction activity of the character and in the localities specified therein.

The determinations in these decisions of such prevailing rates and fringe benefits have been made by authority of the Secretary of Labor pursuant to the provisions of the Davis-Bacon Act of March 3, 1931, as amended (46 Stat. 1494, as amended, 40 U.S.C. 276a) and of other Federal statutes referred to in 29 CFR 1.1 (including the statutes listed at 36 FR 306 following Secretary of Labor's order No. 224-70) containing provisions for the payment of wages which are dependent upon determination by the Secretary of Labor under the Davis-Bacon Act; and pursuant to the provisions of part 1 of subtitle A of title 29 of Code of Federal Regulations, Procedure for Predetermination of Wage Rates (37 FR 21138) and of Secretary of Labor's Orders 12-71 and 15-71 (36 FR 8755, 8756). The prevailing rates and fringe benefits determined in these decisions shall, in accordance with the provisions of the foregoing statutes, constitute the minimum wages payable on Federal and federally assisted construction projects to laborers and mechanics of the specified classes engaged on contract work of the character and in the localities described therein.

Good cause is hereby found for not utilizing notice and public procedure thereon prior to the issuance of these determinations as prescribed in 5 U.S.C. 553 and not providing for delay in effective date as prescribed in that section, because the necessity to issue construction industry wage determination frequently and in large volume causes procedures to be impractical and contrary to the public interest.

General wage determination decisions are effective from their date of publication in the Federal Register without limitation as to time and are to be used in accordance with the provisions of 29 CFR Parts 1 and 5. Accordingly, the applicable decision together with any modifications issued subsequent to its publication date shall be made a part of every contract for performance of the described work within the geographic area indicated as required by an applicable Federal prevailing wage law and 29 CFR, Part 5. The wage rates contained therein shall be the minimum paid under such contract by contractors and subcontractors on the work.

Modifications and Supersedeas Decisions to General Wage Determination Decisions

Modifications and supersedeas decisions to general wage determination decisions are based upon information obtained concerning changes in prevailing hourly wage rates and fringe benefit payments since the decisions were issued.

The determinations of prevailing rates and fringe benefits made in the modifications and supersedeas decisions have been made by authority of the Secretary of Labor pursuant to the provisions of the Davis-Bacon Act of March 3, 1931, as amended (46 Stat. 1494, as amended, 40 U.S.C. 276a) and of other Federal statutes referred to in 29 CFR 1.1 (including the statutes listed at 36 FR 306 following Secretary of Labor's order No. 24-70) containing provisions for the payment of wages which are dependent upon determination by the Secretary of Labor under the Davis-Bacon Act; and pursuant to the provisions of part 1 of subtitle A of title 29 of Code of Federal Regulations, Procedure for Predetermination of Wage Rates (37 FR 21138) and of Secretary of Labor's orders 13-71 and 15-71 (36 FR 8755, 8756). The prevailing rates and fringe benefits determined in foregoing general wage determination decisions, as hereby modified, and/or superseded shall, in accordance with the provisions of the foregoing statutes, constitute the minimum wages payable on Federal and federally assisted construction projects to laborers and mechanics of the specified classes engaged in contract work of the character and in the localities described therein.

Modifications and supersedeas decisions are effective from their date of publication in the Federal Register without limitation as to time and are to be used in accordance with the provisions of 29 CFR Parts 1 and 5.

Any person, organization, or governmental agency having an interest in the wages determined as prevailing is encouraged to submit wage rate information for consideration by the Department. Further information and self-explanatory forms for the purpose of submitting this data may be obtained by writing to the U.S. Department of Labor, Employment Standards Administration, Wage & Hour Division, Office of Government Contract Wage Standards, Division of Construction Wage Determinations, Washington, D.C. 20210. The cause for not utilizing the rulemaking procedures prescribed in 5 U.S.C. 553 has been set forth in the original General Determination Decision.

New General Wage Determination Decisions

Alabama.—AL79-1121.
Oklahoma.—OK79-4089.

Modifications to General Wage Determination Decisions

The numbers of the decisions being modified and their dates of publication in the Federal Register are listed with each State.

Texas:	
TX79-4005; TX79-4009; TX79-4010	Jan. 5, 1979.
TX79-4032; TX79-4033; TX79-4038;	
TX79-4048; TX79-4050	Mar. 16, 1979.
TX79-4051	May 4, 1979.
TX79-4045	June 22, 1979.
TX79-4034	July 13, 1979.
TX79-4036; TX79-4046	Aug. 17, 1979.
Virginia:	
VA78-3075; VA78-3076	Nov. 3, 1978.

Supersedeas Decisions to General Wage Determination Decisions

The numbers of the decisions being superseded and their dates of publication in the Federal Register are listed with each State. Supersedeas Decision numbers are in parentheses following the numbers of the decisions being superseded.

Indiana:	
IN77-2095(IN79-2082)	May 27, 1977.
Kansas:	
KS77-4019(KS79-4090)	Feb. 4, 1977.
New Jersey:	
NJ75-3096(NJ79-3037)	Sept. 19, 1975.
Oklahoma:	
OK79-4018(OK79-4088)	Feb 23, 1979.
Texas:	
TX79-4031(TX79-4086); TX79-4049	
(TX79-4084)	Mar. 16, 1979.

Signed at Washington, D.C., this 28th day of September 1979.

Dorothy P. Come,

Assistant Administrator Wage and Hour Division.

BILLING CODE 4510-27-M

[FR Doc. 79-30618 Filed 10-4-79; 8:45 am]

NEW DECISION

STATE: Alabama. COUNTY: *See below
DECISION NO.: AL79-1121 DATE: Date of Publication
DESCRIPTION OF WORK: Sewer, Water and Storm Drainage Construction Project.

*Counties: Baldwin, Choctaw, Clarke, Conecuh, Escambia, Marengo, Mobile, Monroe, Washington and Wilcox

	Basic Hourly Rates	Fringe Benefits Payments			
		H & W	Pensions	Vacation	Education and/or Appr. Tr.
Carpenters	5.00				
Cement masons-cement finisher	5.50				
Ironworkers, structural and reinforcing	5.70				
Laborers:					
Laborers, unskilled	3.68				
Mortar mixers	3.75				
Pipelayers	3.75				
Truck Drivers:					
Truck drivers	3.25				
Truck drivers - multi rear axle	4.25				
Welders - Rate for Craft.					
POWER EQUIPMENT OPERATORS:					
Backhoe	5.79				
Bulldozer	5.31				
Cranes	5.86				
Loaders	4.25				

Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29 CFR, 5.5 (a)(1)(ii)

NEW DECISION

STATE: Oklahoma COUNTY: Muskogee
DECISION NO. OK79-4089 DATE: Date of Publication
DESCRIPTION OF WORK: Residential projects consisting of single family homes and apartments up to and including 4 stories.

	Basic Hourly Rates	Fringe Benefits Payments			
		H & W	Pensions	Vacation	Education and/or Appr. Tr.
Bricklayers	$6.00				
Carpenters	6.50				
Cement masons	6.25				
Drywall installers	7.40				
Electricians	6.95				
Insulators	6.31				
Laborers	3.75				
Painters, brush	6.20				
Plumbers & Pipefitters	6.92				
POWER EQUIPMENT OPERATORS:					
Backhoe	6.05				
Blade grader	6.45				
Bulldozers	6.45				
Tractors	4.75				
Welders -- receive rate prescribed for craft performing operation to which welding is incidental					
"Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29 CFR, 5.5 (a)(1)(ii)."					

MODIFICATIONS P. 1

	Basic Hourly Rates	Fringe Benefits Payments: H & W	Pensions	Vacation	Education and/or Appr. Tr.
DECISION NO. TX79-4005 - MOD. #5 (44 FR 1675 - January 5, 1979) Bee, Kleberg & Nueces Cos., Texas					
CHANGE:					
Carpenters:					
Carpenters	$ 8.79	.51	.40		.05
Cement masons	9.65				
Ironworkers	9.17	.55	1.15		.07
Roofers:					
Roofers; kettlemen; waterproofers; deckmen	7.60		.25		
Soft floor layers	8.79	.51	.40		.05
Sprinkler fitters	12.79	.75	1.05		.08
DECISION NO. TX79-4009 - MOD. #3 (44 FR 1681 - January 5, 1979) Cameron, Hidalgo, Starr & Willacy Cos., Texas					
CHANGE:					
Sprinkler fitters	12.79	.75	1.05		.08
DECISION NO. TX79-4010 - MOD. #8 (44 FR 1681 - January 5, 1979) Wichita County, Texas					
CHANGE:					
Bricklayers & stonemasons	10.90		.60		.05
Plasterers	11.25				.01
DECISION NO. TX79-4032 - MOD. #4 (44 FR 16325 - March 16, 1979) Harrison County, Texas					
Change modification #2 in the FR of September 7, 1979 on page 52533 to read Modification #3					
CHANGE:					
Sprinkler fitters	12.79	.75	1.05		.08

MODIFICATIONS P. 2

	Basic Hourly Rates	Fringe Benefits Payments: H & W	Pensions	Vacation	Education and/or Appr. Tr.
DECISION NO. TX79-4033 - MOD. #6 (44 FR 16326 - March 16, 1979) Jefferson & Orange Cos., Texas					
CHANGE:					
Sprinkler fitters	12.79	.75	1.05		.08
DECISION NO. TX79-4034 - MOD. #3 (44 FR 41061 - July 13, 1979) Bowie Co., Texas	—				
CHANGE:					
Carpenters:					
Carpenters	9.35				.05
Millwrights	11.65				.05
Piledrivermen	10.15				.05
Sprinkler fitters	12.79	.75	1.05		.08
DECISION NO. TX79-4036 - MOD. #2 (44 FR 48594 - August 17, 1979) Galveston & Harris Cos., Texas					
CHANGE:					
Lathers (Harris Co. only)	12.72	.60	.35		.03
Line Construction:					
Zone 1 - Galveston Co. & that part of Harris Co. from Loop 610 east to State Highway 59, north on State Highway 59 to Highway 1960, west on 1960 to Highway 6, south on Highway 6 to State Highway 59, southeast on State Highway 59 to Loop 610, around Loop 610 to State Highway 59 north)					
Lineman & Cable splicer	13.50	.60	3%		1/2%
Groundman	7.83	.60	3%		1/2%
Zone 2 - Remainder of Harris Co.					
Lineman & cable splicer	13.25	.60	3%		1/2%
Groundman	7.69	.60	3%		1/2%
Plumbers (Harris Co.)	13.22	.75	.80		.12
Sprinkler fitters	12.79	.75	1.05		.08

MODIFICATIONS P. 3

	Basic Hourly Rates	Fringe Benefits Payments: H & W	Pensions	Vacation	Education and/or Appr. Tr.
DECISION NO. TX79-4038 - MOD. #7 (44 FR 16328 - March 16, 1979) Travis County, Texas					
CHANGE:					
Asbestos workers	$11.95	.70	.60		.08
Bricklayers & stonemasons	11.17	.50	.40		.05
Laborers - Group 1	6.655	.275	.40		.02
Group 2	6.805	.275	.40		.02
Group 3	6.98	.275	.40		.02
Group 4	7.055	.275	.40		.02
Painters - Group 2	9.90				
Sprinkler fitters	12.79	.75	1.05		.08
DECISION NO. TX79-4045 - MOD. #3 (44 FR 36694 - June 22, 1979) El Paso County, Texas					
CHANGE:					
Asbestos workers	9.11	.57	1.30		.03
Ironworkers	9.70	.55	1.40		.15
Sheet metal workers	10.72	3%+.51	.485		.06
Sprinkler fitters	12.79	.75	1.05		.08
Power Equipment ops.					
Group 1	7.74	.70	.60		.15
Group 2	8.32	.70	.60		.15
Group 3	8.41	.70	.60		.15
Group 4	9.06	.70	.60		.15
Group 5	9.14	.70	.60		.15
Group 6	9.78	.70	.60		.15
Group 7	9.94	.70	.60		.15
Group 8	9.41	.70	.60		.15
Group 9	9.64	.70	.60		.15
Group 10	9.94	.70	.60		.15
DECISION NO. TX79-4046 - MOD. #1 (44 FR 48593 - August 17, 1979) Brazos County, Texas					
CHANGE:					
Plumbers	13.22	.75	.80		.12

MODIFICATIONS P. 4

	Basic Hourly Rates	Fringe Benefits Payments: H & W	Pensions	Vacation	Education and/or Appr. Tr.
DECISION NO. TX79-4048 - MOD. #6 (44 FR 16330 - March 16, 1979) Armstrong, Carson, Castro, Childress, Collingsworth, Dallam, Deaf Smith, Donley, Gray, Hansford, Hartley, Hemphill, Hutchinson, Lipscomb, Moore, Ochiltree, Oldham, Potter, Randall, Roberts, Sherman, Swisher, & Wheeler Cos., Texas					
CHANGE:					
Painters:					
Group 1	9.70		.50		
Group 2	9.82		.50		
Group 3	10.45		.50		
Group 4	9.95		.50		
Sprinkler fitters	12.79	.75	1.05		.08
DECISION NO. TX79-4051 - MOD. #4 (44 FR 26535 - May 4, 1979) Collin, Dallas, Denton, Ellis, Grayson, Hood, Hunt, Johnson, Kaufman, Palo Pinto, Rockwall, Tarrant & Wise Cos., Texas					
CHANGE:					
Electricians:					
Zone 2 - Electricians	11.75	.60	7%		1%
Cable splicers	12.93	.60	7%		1%
Sprinkler fitters	12.79	.75	1.05		.08
DECISION NO. TX79-4050 - MOD. #6 (44 FR 16334 - March 16, 1979) Bell, Bosque, Coryell, Falls, Hill & McLennan Cos., Texas					
CHANGE:					
Building Construction:					
Asbestos workers-Zone 1	11.95	.70	.60		.08
Sprinkler fitters	12.79	.75	1.05		.08
Incidental Paving & Utilities - See attached schedule					

MODIFICATIONS P. 5

DECISION NO. TX79-4050 -
MOD. #6 (CONT'D)

INCIDENTAL PAVING & UTILITIES	Basic Hourly Rates	Fringe Benefits Payments H & W	Pensions	Vacation	Education and/or Appr. Tr.
Air Tool Man	3.30				
Asphalt Heaterman	4.00				
Asphalt Raker	4.40				
Asphalt Shoveler	4.25				
Batching Plant Scaleman	5.00				
Carpenter	5.30				
Carpenter Helper	3.75				
Concrete Finisher (Paving)	5.25				
Concrete Finisher Helper (Paving)	4.00				
Concrete Finisher (Structures)	5.00				
Concrete Finisher Helper (Structures)	4.25				
Concrete Rubber	3.30				
Electrician	7.00				
Electrician Helper	4.00				
Form Builder (Structures)	4.50				
Form Builder Helper (Structures)	3.30				
Form Setter (Paving & Curb)	4.65				
Form Setter Helper (Paving & Curb)	3.75				
Form Setter (Structures)	4.50				
Form Setter Helper (Structures)	4.00				
Laborer, Common	3.30				
Laborer, Utility Man	3.65				
Mechanic	5.00				
Mechanic Helper	4.10				
Oiler	4.00				
Serviceman	3.50				
Painter (Structures)	3.50				
Piledrivermen	4.00				
Pipelayer:					
Bosque, Falls, Hill & McLennan	4.00				
Pipelayer (Concrete & Clay):					
Bell & Coryell Cos.	4.00				
Pipelayer Helper:					
Bosque, Falls, Hill & McLennan	3.30				
Pipelayer Helper (Concrete & Clay):					
Bell & Coryell Cos.	3.30				

MODIFICATIONS P. 6

DECISION NO. TX79-4050 -
MOD. #6 (CONT'D)

INCIDENTAL PAVING & UTILITIES	Basic Hourly Rates	Fringe Benefits Payments H & W	Pensions	Vacation	Education and/or Appr. Tr.
Plumbers (Bell & Coryell Cos.):					
Zone 1 - 35 miles from Waco - including towns of Temple & Belton	10.17	.30	.40		.04
Zone 2 - all area not included in Zone 1	10.88	.30	.40		.04
Powderman	5.50				
Reinforcing Steel Setter (Structures)	4.90				
Reinforcing Steel Helper	3.30				
Sign Erector	4.65				
Sign Erector Helper	3.30				
Spreader Box Man	4.35				
Swamper	4.25				
Power Equipment Operators:					
Asphalt Distributor	4.40				
Asphalt Paving Machine	4.70				
Broom or Sweeper Op.	4.05				
Bulldozer, 150 HP & Less	4.50				
Bulldozer, over 150 HP	4.75				
Concrete Paving Curing Machine	5.00				
Concrete Paving Saw	4.75				
Crane, Clamshell, Backhoe, Derrick, Dragline, Shovel (less than 1¼ CY)	5.00				
Crane, Clamshell, Backhoe, Derrick, Dragline, Shovel (1¼ CY & over)	5.50				
Crusher or Screening Plant Operator	4.60				
Foundation Drill Operator (Truck Mounted)	4.50				
Foundation Drill Op. Helper	4.25				
Front End Loader (2½ CY & Less)	4.50				
Front End Loader (Over 2½ CY)	5.00				
Motor Grader Op., Fine Grade	6.00				
Motor Grader Operator	4.50				

MODIFICATIONS P. 7

DECISION NO. TX79-4050 - MOD. #6 (CONT'D)

INCIDENTAL PAVING & UTILITIES	Basic Hourly Rates	Fringe Benefits Payments: H & W	Pensions	Vacation	Education and/or Appr. Tr.
Power Equipment Ops. Cont'd:					
Roller, Steel Wheel (Plant-Mix Pavements)	4.25				
Roller, Steel Wheel (Other--Flat Wheel or Tamping)	3.95				
Roller, Pneumatic (Self-Propelled)	3.50				
Scrapers (17 CY and Less)	4.00				
Scrapers (Over 17 CY)	4.60				
Tractor (Crawler Type) 150 HP and Less	3.30				
Tractor (Crawler Type) over 150 HP	4.10				
Tractor (Pneumatic) 80 HP & Less	3.50				
Tractor (Pneumatic) over 80 HP	4.00				
Traveling Mixer	4.10				
Trenching Machine, Light	4.00				
Trenching Machine, Heavy	4.45				
Wagon Drill, Boring Machine or Post Hole Driller Op.	4.00				
Truck Drivers:					
Single Axle, Light	3.55				
Tandem Axle or Semitrailer	4.25				
Lowboy-Float	3.95				
Welder	5.00				
Welder Helper	3.60				

Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29 CFR, 5.5(a)(1)(ii)).

MODIFICATIONS P. 8

	Basic Hourly Rates	Fringe Benefits Payments: H & W	Pensions	Vacation	Education and/or Appr. Tr.
Decision No. VA78-3076-Mod#4 (43 FR 51592-November 3,1978) The cities of Chesapeake, Portsmouth, & Virginia Beach Virginia					
ADD:					
Sound & Signal Installer	$6.00				
Decision No. VA78-3075-Mod#3 (43 FR 51590-November 3,1978) York County and the Cities of Hampton and Newport News (including Langley AFB, Fort Eustis and Fort Monroe) Virginia					
ADD:					
Sound & Signal Installer	$6.00				

SUPERSEDEAS DECISION

STATE: INDIANA COUNTIES: HENDRICKS & MORGAN
DECISION NO.: IN79-2082 DATE: Date of Publication
Supersedes Decision No. IN77-2095, dated May 27, 1977 in 42 FR 27552
DESCRIPTION OF WORK: Residential Construction Projects Consisting of single family homes and apartments up to and including 4 stories.

	Basic Hourly Rates	Fringe Benefits Payments			
		H & W	Pensions	Vacation	Education and/or Appr. Tr.
AIR CONDITIONING AND HEATING MECHANICS	$ 5.00				
BRICKLAYERS	9.06				
CARPENTERS	6.38				
CEMENT MASONS	6.69				
DRYWALL FINISHERS	8.00				
DRYWALL HANGERS	8.00				
ELECTRICIANS	6.63				
LABORERS	4.85				
PAINTERS, Brush	5.00				
PLUMBERS	7.00				
ROOFERS	5.00				
SOFT FLOOR LAYERS	7.80				
POWER EQUIPMENT OPERATORS:					
Backhoes	7.00				
Bulldozers	7.14				

Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29 CFR, 5.5 (a) (1) (ii)).

SUPERSEDEAS DECISION

STATE: Kansas COUNTIES: GEARY & RILEY
DECISION NO: KS79-4090 DATE: Date of Publication
Supersedes Decision No. KS77-4019, dated February 4,1977 in 42 FR 7056
DESCRIPTION OF WORK: Residential construction consisting of single family homes and garden type apartments up to and including 4 stories.

	Basic Hourly Rates	Fringe Benefits Payments			
		H & W	Pensions	Vacation	Education and/or Appr. Tr.
Bricklayers	$10.00				
Carpenters	5.98				
Electricians	5.50				
Laborers	3.00				
Form Setter	4.50				
Mason Tender	4.50				
Painters	3.74				
Plumbers	7.58				
Roofers	6.00				
Sheet Metal Workers	5.53				
Truck Drivers	4.50				
POWER EQUIPMENT OPERATORS:					
Air Compressor	4.00				
Backhoe	6.00				
Bulldozer	6.00				
Concrete Saw	4.30				
Grader	6.00				
Loader	5.50				
Scraper	6.00				
Shovel	5.38				
Tractor	6.00				
Trenching Machine	4.50				

Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29 CFR 5.5(a)(1)(ii)).

SUPERSEDEAS DECISION

STATE: NEW JERSEY COUNTY: BURLINGTON
DECISION NO.: NJ79-3037 DATE: DATE OF PUBLICATION
Supersedes Decision No. NJ75-3096 dated September 19, 1975 in 40 FR 43413
DESCRIPTION OF WORK: Residential Construction Projects consisting of single family houses and apartments up to and including 4 stories

	Basic Hourly Rates	Fringe Benefits Payments H & W	Pensions	Vacation	Education and/or Appr. Tr.
AIR CONDITION AND HEATING MECHANICS	6.15				
BRICKLAYERS	8.10				
CARPENTERS	6.57				
CEMENT MASONS	7.03				
ELECTRICIANS	6.00				
INSULATION MECHANICS	6.02	.25		.14	
LABORERS:					
Laborers	4.21				
Mason Tenders	4.25				
PAINTERS	7.00				
PLUMBERS	6.43				
ROOFERS	8.125				
SHEET METAL WORKERS	6.00				
SHEET ROCK HANGERS	8.00				
TILE SETTERS	6.26				
TRUCK DRIVERS	5.00				
POWER EQUIPMENT OPERATORS:					
Backhoes	6.50				
Bulldozers	6.35				
Drillers	5.65				
Front End Loaders	6.50				
Graders	6.50				
Pavers	6.58				
Rollers	5.50				

Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29 CFR 5.5(a)(1)(ii)).

SUPERSEDEAS DECISION

STATE: Oklahoma COUNTY: Tulsa
DECISION NO. OK79-4088 DATE: Date of Publication
SUPERSEDES DECISION NO. OK79-4018 dated February 23, 1979 in 44 FR 10951
DESCRIPTION OF WORK: Residential projects consisting of single family homes and apartments up to and including 4 stories.

	Basic Hourly Rates	Fringe Benefits Payments H & W	Pensions	Vacation	Education and/or Appr. Tr.
Bricklayers	$8.93				
Carpenters	6.58				
Cement masons	6.80				
Drywall Installers	7.50				
Electricians	5.55				
Air conditioning & Heating	5.65				
Ironworkers	5.51				
Laborers:					
Laborers	4.72				
Pipelayers	5.00				
Painters, brush	6.00				
Plumbers & Pipefitters	6.89				
Roofers	7.79				
Sheet metal workers	5.44				
Soft floor layers	7.36				
Tile setters	9.50				
Tile setters finishers	5.00				
POWER EQUIPMENT OPERATORS:					
Concrete pump	5.75				
Tractors	5.50				

WELDERS -- receive rate prescribed for craft performing operation to which welding is incidental.

"Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29 CFR, 5.5 (a) (1) (ii).

SUPERSEDEAS DECISION

STATE: Texas
COUNTY: Howard
DECISION NO.: TX79-4084
DATE: Date of Publication
Supersedes Decision No. TX79-4049, dated March 16, 1979 in 44 FR 16322
DESCRIPTION OF WORK: Building (including Residential) Projects.

	Basic Hourly Rates	Fringe Benefits Payments			
		H & W	Pensions	Vacation	Education and/or Appr. Tr.
BRICKLAYERS	$ 7.00				
CARPENTERS	6.10				
CEMENT MASONS	5.00				
ELECTRICIANS	7.40	.30	1%		1/10%
IRONWORKERS, Structural & Ornamental	9.75	.55	1.15		.10
LABORERS:					
Laborers	3.06				
Mason tenders	3.50				
PAINTERS	4.50				
PLUMBERS	4.26				
ROOFERS	4.00				
SHEET METAL WORKERS	5.25				
TILE SETTERS	4.00				
TRUCK DRIVERS	2.90				
WELDERS -receive rate prescribed for craft performing operation to which welding is incidental.					

Unlisted classification needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29 CFR, 5.5(a)(1)(ii)).

DECISION NO. TX79-4084

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INCIDENTAL PAVING & UTILITIES (BUILDING CONSTRUCTION)
INCIDENTAL PAVING & UTILITIES & SITE PREPARATION (RESIDENTIAL CONSTRUCTION)

	Basic Hourly Rates	Fringe Benefits Payments			
		H & W	Pensions	Vacation	Education and/or Appr. Tr.
Air Tool Man	3.45				
Asphalt Heaterman	3.75				
Asphalt Raker	4.00				
Asphalt Shoveler	3.50				
Batching Plant Scaleman	4.50				
Batterboard Setter	3.65				
Carpenter	4.75				
Carpenter Helper	3.80				
Concrete Finisher (Paving)	4.80				
Concrete Finisher Helper (Paving)	3.45				
Concrete Finisher (Structures)	4.85				
Concrete Finisher Helper (Structures)	4.20				
Electrician	7.50				
Form Builder (Structures)	5.05				
Form Builder Helper (Structures)	4.00				
Form Liner (Paving & Curb)	4.00				
Form Setter (Paving & Curb)	4.70				
Form Setter Helper (Paving & Curb)	4.00				
Form Setter (Structures)	4.75				
Form Setter Helper (Structures)	3.75				
Laborer, Common	3.45				
Laborer, Utility Man	4.10				
Manhole Builder, Brick	3.45				
Mechanic	4.85				
Mechanic Helper	3.75				
Oiler	4.00				
Serviceman	4.10				
Painter (Structures)	6.00				
Painter Helper (Structures)	3.50				
Pipelayer	4.00				
Pipelayer Helper	3.50				
Powderman	4.50				
Powderman Helper	3.55				
Reinforcing Steel Setter (Structures)	4.90				
Reinforcing Steel Setter Helper	3.85				

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INCIDENTAL PAVING & UTILITIES (BUILDING CONSTRUCTION)
INCIDENTAL PAVING & UTILITIES & SITE PREPARATION (RESIDENTIAL CONSTRUCTION)

	Basic Hourly Rates	Fringe Benefits Payments H & W	Pensions	Vacation	Education and/or Appr. Tr.
Sign Erector	4.00				
Sign Erector Helper	3.50				
Spreader Box Man	4.20				
Swamper	4.25				
Power Equipment Operators:					
Asphalt Distributor	4.35				
Asphalt Paving Machine	4.50				
Broom or Sweeper Operator	4.00				
Bulldozer, 150 HP & Less	4.50				
Bulldozer, over 150 HP	4.90				
Concrete Paving Finishing Machine	3.50				
Concrete Paving Saw	4.50				
Paving Sub Grader	4.25				
Crane, Clamshell, Backhoe, Derrick, Dragline, Shovel (less than 1½ CY)	4.75				
Crane, Clamshell, Backhoe, Derrick, Dragline, Shovel (1½ CY & Over)	5.45				
Crusher or Screening Plant Operator	4.50				
Elevating Grader	4.10				
Foundation Drill Operator (Crawler Mounted)	8.00				
Foundation Drill Operator (Truck Mounted)	7.00				
Foundation Drill Operator Helper	4.85				
Front End Loader (2½ CY & Less)	4.30				
Front End Loader (Over 2½ CY)	5.10				
Hoist (Double Drum & Less)	4.00				
Motor Grader Op., Fine Grade	5.85				
Motor Grader Operator	4.95				
Roller, Steel Wheel (Plant-Mix Pavements)	3.95				
Roller, Steel Wheel (Other-Flat Wheel or Tamping)	3.50				

DECISION NO. TX79-4084 Page 4

INCIDENTAL PAVING & UTILITIES (BUILDING CONSTRUCTION)
INCIDENTAL PAVING & UTILITIES & SITE PREPARATION (RESIDENTIAL CONSTRUCTION)

	Basic Hourly Rates	Fringe Benefits Payments H & W	Pensions	Vacation	Education and/or Appr. Tr.
Power Equipment Ops. (Cont'd):					
Roller, Pneumatic (Self-Propelled)	3.50				
Scraper (17 CY & Less)	4.25				
Scrapers (Over 17 CY)	4.50				
Self-Propelled Hammer	3.50				
Side Boom	3.50				
Tractor (Crawler Type) 150 HP and Less	3.70				
Tractor (Crawler Type) over 150 HP	4.00				
Tractor (Pneumatic) 80 HP & Less	3.75				
Tractor (Pneumatic) over 80 HP	4.10				
Traveling Mixer	4.00				
Trenching Machine, Light	4.35				
Trenching Machine, Heavy	5.75				
Wagon Drill, Boring Machine or Post Hole Driller Op.	4.20				
Truck Drivers:					
Single Axle, Light	3.50				
Single Axle, Heavy	3.65				
Tandem Axle or Semitrailer	3.90				
Lowboy-Float	4.45				
Transit-Mix	4.10				
Winch	4.25				
Welder	5.00				

Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29 CFR,5.5(a)(1)(ii)).

SUPERSEDEAS DECISION

STATE: Texas COUNTY: Bexar
DECISION NO.: TX79-4086 DATE: Date of Publication
Supersedes Decision No. TX79-4031, dated March 16, 1979, in 44 FR 16324
DESCRIPTION OF WORK: Building Projects (does not include single family homes and apartments up to and including 4 stories). (Use current heavy & highway general wage determination for Paving & Utilities Incidental to Building Construction).

	Basic Hourly Rates	Fringe Benefits Payments: H & W	Pensions	Vacation	Education and/or Appr. Tr.
ASBESTOS WORKERS	11.95	.70	.60		.08
BOILERMAKERS	11.05	.80	1.00		.02
BRICKLAYERS & STONEMASONS	10.80	.45	.30	.25	.05
CARPENTERS:					
Carpenters	10.04	.48	.50	.40	.05
Millwrights	10.34	.48	.50	.40	.05
CEMENT MASONS	10.25	.45		.65	.02
ELECTRICIANS:					
Electricians	11.69	.60	5%		1%
Cable splicers	11.94	.60	5%		1%
ELEVATOR CONSTRUCTORS:					
Mechanics	10.34	.895	.69	4%+a+b	.035
Helpers	70%JR	.895	.69	4%+a+b	.035
Helpers (Prob.)	50%JR				
GLAZIERS	6.80				
IRONWORKERS	9.50	.55	1.15	.50	.12
LABORERS:					
GROUP 1 - General laborers	6.32	.47	.40		.05
GROUP 2 - All power tools & equipment operators; cutting torch man; power buggy op.; wagon drill op.; well driller; drilling rig tender; cement finisher tender; handling creosoted materials; scale man on batch plants; asphalt raker; concrete & clay & all non-metallic pipe laying; plasterer tender; brick tender; lather tender	6.57	.47	.40		.05
GROUP 3 - Mortar mixer man; grout machines; pumpcrete machines; gunnite mixing machines; running sand dryer & loading; operating sand blaster; bell hole man; blaster, powderman; gunnite nozzleman	6.67	.47	.40		.05

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DECISION NO. TX79-4086

	Basic Hourly Rates	Fringe Benefits Payments: H & W	Pensions	Vacation	Education and/or Appr. Tr.
LINE CONSTRUCTION:					
Lineman	12.09	.60	3%		1/2%
Cable splicer	12.34	.60	3%		1/2%
Groundman	6.65	.60	3%		1/2%
MARBLE SETTERS	9.69	.45	.30	.25	
MARBLE SETTERS' FINISHERS	6.87				
PAINTERS:					
Brush; paperhanger; taper & floater; hand roller	9.50		.20		.05
Brush on all structural steel; spray on any other surface other than steel	9.75		.20		.05
PLUMBERS & PIPEFITTERS	11.48	.55	.55		.10
ROOFERS:					
Roofers; deckman	6.95	.25			
Kettlemen	6.18	.25			
Waterproofers	6.54	.25			
SHEET METAL WORKERS	10.89	3%+.45	.77		.07
SOFT FLOOR LAYERS	6.35				
SPRINKLER FITTERS	12.79	.75	1.05		.08
TERRAZZO WORKERS	9.69	.45	.30	.25	
TERRAZZO WORKERS' FINISHERS:					
Terrazzo finishers	6.87				
Floor machine operators	7.07				
Base machine operators	7.22				
TILE SETTERS	9.69	.45	.30	.25	
TILE SETTERS' FINISHERS	6.87				
TRUCK DRIVERS	3.64				
WELDERS - receive rate prescribed for craft performing operation to which welding is incidental.					

PAID HOLIDAYS FOR ELEVATOR CONSTRUCTORS:
A-New Years' Day; B-Memorial Day; C-Independence Day; D-Labor Day; E-Thanksgiving Day; F-the Friday after Thanksgiving Day; G-Christmas Day

FOOTNOTES FOR ELEVATOR CONSTRUCTORS:
a - 1st 6 mos. - none; 6 mos. to 5 years, - 2%; over 5 yrs. - 4% of basic hourly rate
b - Paid Holidays A thru G

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DECISION NO. TX79-4086

	Basic Hourly Rates	Fringe Benefits Payments			
		H & W	Pensions	Vacation	Education and/or Appr. Tr.
POWER EQUIPMENT OPERATORS					
GROUP 1	9.27	.45	.75		
GROUP 2	8.28	.45	.75		
GROUP 3	6.98	.45	.75		
GROUP 4	6.71	.45	.75		

POWER EQUIPMENT OPERATORS CLASSIFICATION DEFINITIONS

GROUP 1 - All foundation drilling rigs; all rollers (5 tons or over); backfiller; backhoe; blade graders (self-propelled); bull clam; bulldozers; cableway; clamshell operator; crane (power operated, all types); derricks (power operated, all types); draglines; DW-10 caterpillar and similar tractors; elevating graders (self-propelled); euclid; fork lift used on construction; gasoline or diesel-driven welding machines (7 to 12); gradall; heavy duty mechanic; high lifts; hoist (two drums or more); locomotives; mixer (14 cu. ft. or over); mixmobile; paving mixers (all sizes); piledriver; pumpcrete machine operator; rock crusher operator on job; scoopmobile; scrapers; shovel (power operated); turnapulls; trenching machines (all sizes); winch truck

GROUP 2 - Air compressor (any time there are three or more attachments operating on a 125 cu. ft. air compressor or less, a light equipment operator shall be employed. Any compressor over 125 cu. ft. shall have a light equipment operator); blade graders (towed); building elevator used on construction; flex planes; form graders; hoist (single drum); mixer (less than 14 cu. ft.); pneumatic roller; pulsometers; pump (2½ or larger shall require a light equipment operator); three to six welding machines or any three pieces or equipment of equal or similar nature

GROUP 3 - Fireman

GROUP 4 - Oiler

Unlisted classifications needed for work not included within the scope of the classifications listed may be added after award only as provided in the labor standards contract clauses (29 CFR, 5.5(a)(1)(ii)).

BILLING CODE 4510-27-C

federal register

Friday
October 5, 1979

Part III

Federal Communications Commission

Inquiry and Proposed Rulemaking; Deregulation of Radio

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Parts 0, 73

[BC Docket No. 79-219: FCC 79-518]

Inquiry and Proposed Rulemaking; Deregulation of Radio

AGENCY: Federal Communications Commission.

ACTION: Notice of Inquiry and Notice of Proposed Rule Making.

SUMMARY: With this Notice, the Commission proposes to modify or eliminate certain rules applicable to commercial radio broadcast stations. The proposed deregulation encompasses limits on commercial matter, guidelines for the amount of non-entertainment programming, and formalized procedures for the ascertainment of community needs and interests.

DATES: Comments must be received on or before January 25, 1980, and reply comments must be received on or before April 25, 1980.

ADDRESS: Federal Communications Commission, Washington, D.C. 20554.

FOR FURTHER INFORMATION CONTACT: Roger Holberg, Broadcast Bureau, (202) 632-6302.

SUPPLEMENTARY INFORMATION:

Adopted: September 6, 1979.

Released: September 27, 1979.

In the matter of deregulation of radio, BC Docket No. 79-219, RM-3099, RM-3273.

By the Commission: Commissioners Ferris (Chairman), Quello, and Brown issuing separate statements; Commissioners Lee and Jones concurring and issuing separate statements; Commissioners Washburn and Fogarty concurring in part, dissenting in part, and issuing separate statements.

I. Introduction

1. We are today initiating a proceeding looking toward the substantial deregulation of commercial broadcast radio. The Commission is proposing rule and policy changes that would remove current requirements in nontechnical areas including nonentertainment programming, ascertainment, and commercialization. This represents a clear departure from our present involvement in such matters and we therefore solicit comments on these proposed changes. In this proceeding, we will examine existing and proposed policies and regulations relevant to these areas as they affect all commercial radio licensees without regard to the size of the market in which they are located or the nature of service that they provide.

2. The proceeding that we are instituting reflects the Commission's continuing concern that its rules and policies should be relevant to an industry and a technology characterized by dynamic and rapid change. It also reaffirms the Commission's commitment to fostering a broadcast system that maximizes the well-being of the consumers of broadcast programming. The present proceeding does not represent a sudden change in direction. In 1972, the Commission commenced a re-regulation study and created a multidiscriplinary Reregulation Staff to examine all technical broadcast rules.[1] The object of this study was to determine the validity of such rules given current broadcasting art and technology. The process has been a continuing one. The Commission has either relaxed or deleted rules it has determined were no longer necessary or appropriate. In this effort, over 800 rule revisions and deletions have been made since 1972. Most recently, we adopted an Order further reorganizing, restructuring and revising Part 73 of Volume III of the Commission's rules pertaining to broadcast services.[2] The deregulation process itself was commenced on October 19, 1978, when the Commission asked the Broadcast Bureau, the Office of Plans and Policy, and the General Counsel to review the scope of existing Commission regulation of radio. Additionally, the Commission staff was asked to supply a set of options for potential reduction or elimination of regulations no longer appropriate to certain marketplace conditions and whose elimination would be consistent with the Commission's public interest obligations.[2A] The Commission considered staff proposals in this regard at a meeting on May 8, 1979. The proposals in this Notice reflect the Commission's concerns as expressed at that meeting.

3. The growth of the radio industry since 1912 has led to continuing changes in what we require of broadcast licensees. We have long been, and remain, committed to the principle that radio must serve the needs of the public. We have never, however, believed that radio is a static medium that requires the retention of every rule and policy once adopted. A regulation that was reasonable when adopted, and appropriate to meet a given problem, may be most inappropriate if retained once the problem ceases to exist.[3] In our view, it is vital that our rules and policies be appropriate for the industry and marketplace we regulate, reducing regulation to the maximum extent consistent with the public interest, convenience and necessity. We note in passing that Congress is now examining whether legislative reform is necessary to foster optimum development of all communications industries, including broadcasting. Additionally, the President has ordered Executive Agencies to adopt procedures to improve existing and future regulations, including the deletion of unneeded ones.[4]

4. The fundamental departure we are proposing raises a number of issues for our consideration. Among the matters that must be addressed are:

[1] *See*, Public Notice entitled "Broadcast Regulation Study," FCC Mimeo No. 83444, April 6, 1972.

[2] *See*, Order released June 22, 1979, (FCC 79-371), Mimeo No. 5921.

[2A] This was followed on December 11, 1978, by the filing of a Petition for Rule Making by the National Association of Broadcasters seeking the deregulation of radio in the areas of delegations of authority on commercial and nonentertainment program levels, ascertdainment and program logging requirements. These were precisely the areas that the Commission had requested the Broadcast Bureau, Office of Plans and Policy, and General Counsel to address and that are the subject of this Notice. NAB had previously filed a Petition for Rule Making (RM-3099) requesting the deletion of the Broadcast Bureau's delegation of authority with regard to commercial time standards for AM and FM radio. On February 15, 1979, the Michigan Association of Broadcasters filed comments in support of the December 11, 1978, NAB filing. The issues raised by both of the above-described NAB petitions, and comments upon them, will be considered in this proceeding. In addition to these matters, the Commission has before it a number of other proceedings concerning radio programming that may be at least partically affected by the instant rule making. These include the following: (1) BC Docket Number 78-237, RM-2937, Notice of Proposed Rule Making on Amendment of the Primers on Ascertainment of Community Problems by Commercial Broadcast Renewal Applicants and Noncommercial Educational Broadcast Applicants; (2) BC Docket Number 78-335, RM-2709, Notice of Inquiry on Adding a New Program Type, "Community Service" Program, and Expanding the "Public Affairs" Program Category; (3) BC Docket No. 78-251, RM-2712, Notice of Inquiry on the Airing of Public Service Announcements by Broadcast Licensees; and (4) RM-3366, Petition for rule making concerning revised procedures for the comparative hearing process for new applicants. We also note our experiment with respect to the ascertainment documentation exemption for small market broadcasters. Any actions that are taken in these cases will be coordinated and consistent with any action taken in this proceeding.

[3] *Home Box Office, Inc.* v. *F.C.C.*, 567 F. 2d 9, 36 (D.C. Cir. 1977), citing *City of Chicago* v. *F.P.C.*, 458 F. 2d 731, 742 (D.C. Cir. 1971), *cert. denied*, 405 U.S. 1074 (1972).

[4] Executive Order No. 12044, March 23, 1978, 43 FR 12661. Although this Order does not apply to the Commission, which is not an Executive Agency, it clearly evidences a national policy to reduce the burdens imposed by unnecessary governmental regulation.

A. What were the conditions, especially in the radio marketplace, that led to our current rules and policies?

B. To what extent have those conditions changed since our adoption of those rules and policies, and what effect do those changes have upon the need for such rules and policies?

C. Are the burdens association with our rules, policies and regulations justified by their benefits? In measuring those benefits, has appropriate consideration been given to how closely our rules, policies, and regulations attain their intended public interest goals? Are those goals themselves in the public interest?

D. To what extent are consumer needs, wants, and desires met by the market under the current regulatory scheme? Would they be better met in the absence of some or all of our current policies, rules, or regulations?

E. How should the Commission weigh consumer needs, wants, and desires in establishing those policies, rules and regulations? Should they be given greater deference than currently in determining what is in the public interest?

F. If current Commission policies, rules, and regulations are unneeded, ineffective, or inappropriate, for whatever reason, which option or options for removing or relaxing them is the most appropriate, and what problems legal or otherwise, does the Commission face in doing so?

Because this proceeding involves fundamental matters of Commission rules and policies, we invite the public to comment on the above and any other aspects of our proposal.

II. Historical Perspective

A. General

5. The first attempt by the government to regulate radio was the Radio Act of 1912. That Act primarily made the Secretary of Commerce and Labor responsible for the licensing of radio stations and operators. That Act was not sufficient, however, to cope with the fledgling radio field. In 1923, the courts ruled that under the 1912 Act the Secretary of Commerce and Labor could not refuse to issue a license not specifically barred by the statute.[5] In 1926, the Secretary was found to lack authority under the Act to fix wavelengths within authorized bands upon which licensees could operate, or to specify periods of operation.[6] Thus, the government was left without any descretionary authority to choose among applicants, to specify hours of operation, or to assign frequencies. The Secretary of Commerce and Labor was left with only the ministerial duty of issuing licenses to applicants. Therefore, he abandoned all other attempts at regulation.

6. The situation in radio quickly became chaotic. Radio stations increased their power and changed their operating hours and frequencies at will in "a frenzied effort to enlarge their coverage areas, reach larger audiences, and achieve competitive advantage."[7] The period has been described as one in which "chaos rode the air waves, pandemonium filled every loud-speaker and the twentieth century Tower of Babel was made in the image of the antenna towers of some thousand broadcasters who, like the Kilkenny cats, were about to eat each other up."[8]

7. The radio field during the period prior to 1927 was also characterized by the advent and growth of networks. Even prior to the first network broadcast on January 4, 1923, steps were taken in the radio industry to form a comprehensive, vertically integrated type of "network" that is unknown today. The Radio Corporation of America, formed and largely owned by General Electric, was able to secure properties and patents owned by the American Marconi Company. However, to bring about the intended radio monopoly, other patents had to be brought under the control of RCA. Accordingly, agreements were negotiated with the American Telephone and Telegraph Company, Westinghouse, and their affiliates whereby they became stockholders in RCA and cross-licensed the patents.[9] Thus the patents for the crucial components of radio transmission and reception were brought together in one consortium. Each of the partners in this consortium was given the right to engage in specific aspects of the industry.

8. Westinghouse, General Electric and RCA, the so-called radio group, were authorized to manufacture and sell radio receivers while AT&T and Western Electric, the so-called telephone group, were given control of telephonic communications by wire and by radio and the right to manufacture transmitters.[10] Within two years after this arrangement was finalized the actual network broadcasting of radio programs commenced. Strains developed in the consortium, however, when AT&T, the initiator of network broadcasts, refused to rent long distance telephone lines to RCA for use by its network due to a dispute over RCA's authority to engage in radio broadcasting under the cross-licensing agreements.

9. Because of (1) the dispute, (2) public dissatisfaction with what had become known as the "radio trust" and (3) the possibility of government antitrust action against RCA and the other partners, AT&T withdrew from both broadcasting and the consortium by selling its network to the National Broadcasting Company, an RCA subsidiary, in 1926.[11] NBC, which was owned in varying proportions by RCA, GE and Westinghouse, thus was able to maintain two networks, the Red and the Blue networks. The next year, 1927, saw the founding of a new network, which became the Columbia Broadcasting System. Thus, in addition to the chaotic conditions on the airwaves described above, the early history of broadcasting in this country was characterized by the rise of networks, controlled by a few.

10. The combination of noncompetitive programming and frequency chaos convinced Secretary of Commerce Herbert Hoover of the necessity for government regulation of broadcasting. In 1922, he called the first of a series of conferences of radio experts. That conference, which lasted for two months, recommended the extension of the Secretary's authority to regulate radio. Although legislation in Congress was proposed to that end, none was passed. Additional conferences were convened by Secretary Hoover and additional legislation was introduced without conclusive result.[12] Finally, legislation which was to become the Radio Act of 1927 was introduced and hearings were held.

11. Secretary Hoover testified at the hearings, expressing two major points. The first was that legislation was

[5] *Hoover* v. *Intercity Radio Company*, 286 Fed. 1003 (D.C. Cir. 1923).

[6] *United States* v. *Zenith Radio Corp.*, 12 F. 2d (N.D. Ill. 1926). This case held that a licensee could not be criminally prosecuted for its failure to operate at authorized times on authorized wavelengths. Subsequently, the Attorney General issued an opinion concluding the Secretary had no authority to make such assignments.

[7] Emery, *Broadcasting and Government*, Michigan State University Press, 1971, page 23.

[8] *Id.*, pages 23–24, citing, Chase, *Sound and Fury*, New York, 1942, page 21.

[9] Hybels and Ulloth, *Broadcasting, An Introduction to Radio and Television*, D. Van Nostrand Co., New York, 1978.

[10] *Id.*, page 53.

[11] *Id.*, page 61.

[12] It is interesting to note that although Hoover was in favor of federal regulation of radio he withdrew his support of one bill because he felt that the rapidly changing state of radio necessitated additional experience prior to the passage of legislation that might impede flexibility. The rapidly changing nature of broadcast radio has been a continuing phenomenon and is one of the factors leading us to the action that we are currently proposing.

necessary to properly allocate frequencies. At the time of the Congressional hearings there were 536 broadcast stations operating on 89 wavelengths, which was thought to be the limit of available frequencies. The second was to assure that no individual, group, or combination would have the right to determine what communications could be made available to the American people.[13] Hoover's comments in this regard[14] clearly were in reference to the "radio trust" and indicated a belief in the desirability of diversity, of a multitude of voices being heard over the airwaves. Concern about the possibility of a radio trust underlay Hoover's warning that:

> Radio communication is not to be considered as merely a business carried on for private gain, for private advertisement, or for entertainment of the curious. It is a public trust and to be considered primarily from the standpoint of public interest to the same extent and upon the basis of the same general principles as our other public utilities.[15]

12. The legislative history of the Radio Act of 1927 reveals that Congress feared that control of the radio industry by a small group would lead to censorship, mal-distribution of, and discrimination in, service. Accordingly, Congress enacted the Radio Act of 1927, mandating that radio stations were to be operated in "the public interest," a term that at the time was primarily used with regard to public utilities regulation. As will be more fully discussed below, Congress did not define the phrase or enumerate its elements.

13. Subsequently, the Communications Act of 1934 was enacted, centralizing the regulatory authority over radio in the Federal Communications Commission. Previously, such authority resided in the Interstate Commerce Commission, the Federal Radio Commission, and, to some extent, the Postmaster General. The Communications Act of 1934, however, did not undertake to change in any substantive manner the radio law as it existed under the Radio Act, and the objectives of the Communication Act were substantially unaltered from those of the 1927 Act.[16]

14. Both the Radio Act of 1927, and the Communications Act of 1934, were enacted within particular historical contexts. For instance, in 1927, there were some 681 broadcast stations; by 1934, this had fallen to 583 stations. Because of the geographic distribution of these stations, in 1929 approximately 40% of the population of the United States were "distant listeners" remote from any broadcast station.[17] In 1925, only 10% of American households had a radio. By 1935, 67% were so equipped.[18] There were no alternate sources of broadcast news and public affairs programming—television had not yet been developed and neither commercial FM nor educational broadcast stations existed. Aside from newsreels shown in movie theaters, news sources were limited primarily to the print media, newspapers and periodicals. In 1927, there were 1,949 daily and 526 Sunday newspapers; these numbers decreased slightly by 1934.[19] Thus, the period was characterized by disorder on the airwaves, concentration of control within the broadcasting industry, no alternate broadcast sources for news and public affairs information, and inaccessibility of large portions of the population to broadcast stations and signals.

14. Because of the limited number of raido stations and competing media sources, there was concern about the type of programming that would be broadcast. As a result it was not long before the government become involved in determining what types of programming were, and were not, in the public interest. Several rationales were offered for this involvement. While alternate theories exist justifying government intrusion into programming, the most widely accepted one is the scarcity theory. The origins of that theory predate even the enactment of the Radio Act of 1927.

15. The Fourth National Radio Conference called by Secretary Hoover recommended to Congress that certain principles be incorporated in any radio act to be enacted by Congress. One of these was to require licensees to either render a benefit to the public, be necessary in the public interest, or contribute to the development of the radio art. The reasoning behind this recommendation was that because spectrum space was limited, not all applicants could be granted licenses. There would have to be a basis for choosing among applicants. This approach was shared by, among others, Congressman White, the House sponsor of what was to become the Radio Act of 1927. The next logical step was to create a government regulatory agency to determine what constituted a benefit to the public. Presumably any such benefits were derived from the programming. Hence, regulation of programming.

16. This rationale has enjoyed great longevity. For instance, Justice Frankfurter's opinion in *National Broadcasting Company* v. *United States*[21] concluded that the chaos present on the airwaves prior to the Radio Act necessitated governmental regulation which would result in too few frequencies to accommodate all applicants. Accordingly, he continued, this scarcity required that licenses be granted to aplicants based in part upon a consideration of their programming. Still later, Congress, when considering the amendment of Section 315 of the Communications Act of 1934, noted that, "broadcast frequencies are limited and, therefore, they have been necessarily considered a public trust." [22]

17. More recently, the scarcity doctrine was reaffirmed in *Red Lion Broadcstmg Co.* v. *F.C.C., supra.* The Court, in *Red Lion,* found that the Commission could require a licensee to afford persons who had been personally attacked over the licensee's facility the opportunity to respond without violating the licensee's First Amendment rights. One of the factors that strongly influenced the Court in its decision was the scarcity of radio frequencies. The Court stated that scarcity was not "entirely a thing of the past" and that although there had been advances in the efficient use of the frequency spectrum, this scarcity impelled its regulation by the Commission. The Court concluded that in view of the scarcity of broadcast frequencies the Commission's challenged regulations did not violate the First Amendment.

18. Based upon its mandate to operate in the public interest, which stemmed in part from the scarcity rationale, the Commission and its predecessor agency, the Federal Radio Commission, undertook to regulate broadcasting. This regulation involved licensees' programming almost from the start. It was clear in the Congressional debates leading to the passage of the 1927 Act that Congress saw the government as

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[13] Of the 89 effective wavelengths available, 70 were said to be controlled by RCA. See, 68 Cong. Rec. 3030.

[14] Read into the record at 67 Cong. Rec. 5483, 5484.

[15] *Id.* at 5484.

[16] *Federal Communications Commission* v. *Pottsville Broadcasting Co.* 309 U.S. 134, 137 (1940).

[17] Testimony of Commissioner Orestes H. Caldwell, Federal Radio Commission, before the Committee on the Merchant Marine and Fisheries, House of Representatives, 70th Congress, 2nd Session, on H.R. 15430, page 451.

[18] Hybels and Ulloth, *supra.,* page 72, Citing, Lichty and Topping, *A Source Book on the History of Radio and Television,* (New York: Hastings House, 1975), p. 521.

[19] United States Bureau of the Census, *Historical Statistics of the United States, Colonial Time to 1957,* Washington, D.C. 1960, page 506, Library of Congress Card No. A 60 9150.

[21] 319 U.S. 190 (1943).

[22] This quotation from the Senate report on the amendment of Section 315 in 1959 is cited in *Red Lion Broadcasting Company* v. *F.C.C.,* 395 U.S. 367, 376 (1969).

having a proper role in the regulation of programming. Senator Dill, the Act's sponsor in the Senate, felt that the whole basis of the Radio Act was public service to the listeners.[23] That service can only be rendered through programming and thus Congress saw that the regulatory body that they were creating would have the authority to act in that area where required by the public interest.

19. It was not long before that authority was translated into action. The Federal Radio Commission stated in its 1928 Annual Report to Congress that it believed that it was, "* * * entitled to consider the program service rendered by the various applicants, to compare them, and to favor those which render the best service."[24] Moreover, its renewal forms requested that licensees:

> (11) Attach printed program for the last week.
> (12) [Explain] Why will the operation of the station be in the public convenience, interest and necessity?
> (a) Average amount of time weekly devoted to the following services (1) entertainment (2) religious (3) commercial (4) educational (5) agricultural (6) fraternal.

At the same time, however, the Commission recognized that it would be inappropriate for it to "erect a rigid schedule specifying the hours or minutes that may be devoted to one kind of program or another."[25] The Commission, while concerned with the public's First Amendment interests in radio, was also sensitive to the broadcasters' right of free speech. Of this tension, Stephen Davis, the Solicitor of the Department of Commerce—which was the agency initially charged with the task of radio regulation—wrote:

> The character of the programs furnished is an essential factor in the determination of the public interest but a most difficult test to apply, for to classify on this basis is to verge on censorship. Consideration of programs involves questions of taste, for which standards are impossible. It necessitates the determination of the relative importance of the broadcasting of religion, instruction, news, market reports, entertainment, and a dozen other subjects.[26]

20. With the passage of the Communications Act of 1934, the regulatory authority was transferred to the Federal Communications Commission. The public interest standard, however, remained and the Act has generally been viewed as having the same objectives as the Radio Act of 1927.[27] In fact, most of Title III of the 1934 Act, which governs broadcast regulation, was virtually identical to the provisions of the Radio Act of 1927.[28] Thus, the Commission to some extent was empowered by Congress to continue its regulatory concern with the types of programs offered by its licensees.[29]

B. The Development of Present Informational Programming Regulation

21. Among the first major Commission policy statements on programming was its 1946 *Report on Public Service Responsibility of Broadcast Licensees.*[30] This document came to be known as *The Blue Book.*[31]

While the *Blue Book* stressed that,

> [I]n granting and renewing licenses, the Commission has goven repeated and explicit recognition to the need for adequate reflection in programs of local interests, activities and talent,[32]

It also noted that:

> Primary responsibility for the American system of broadcasting rests with the licensees of broadcast stations, including the network organizations. It is to the stations and networks rather than to federal regulation that listeners must turn for improved standards of program service.[33]

Although the Commission asserted that, "the public interest clearly requires that an adequate amount of time be devoted to the discussion of public issues," and that at least some portion of the broadcast day should consist of "local live" and "sustaining" (nonsponsored) broadcasts, it refrained from specifying particular amounts of time to be devoted to such programming.

22. The Commission's discussion of the two specific kinds of programming noted above—sustaining and local live programming—sheds some light on how it viewed both the commercial aspect of broadcasting and localism in the 1940's. Sustaining programs were regarded as serving a five-fold function: (1) Maintaining an overall program balance; (2) providing time for programs inappropriate for sponsorship; (3) providing time for programs serving particular minority needs and interests; (4) providing time for nonprofit organizations; and (5) providing time for experimental and unfettered artistic expression.[34] It was the Commission's view that a well-balanced program structure could not be assured if programming decisions were influenced primarily or predominantly by either local sponsors or national advertisers. The extent of radio time devoted to "soap operas" was used to illustrate this potential for imbalance: in 1940 the four networks provided listeners with 59½ daytime hours of sponsored programs weekly, and of these, 55 hours were devoted to soap operas. With respect to local live programming, the Commission restated its continuing concern that such programming reflect local interests, public expression, activities, and talent.

23. The *Blue Book* also discussed the relevance of the market in the provision of programming. It stated:

> [I]n Metropolitan areas where the listener has his choice of several stations, balanced service to listeners can be achieved either by means of a balanced program structure for each station or by means of a number of comparatively specialized stations *which, considered together, offer a balanced service to the community.*[35] (Emphasis added.)

Similarly, the Commission made this point in discussing revisions of the broadcast application form when it stated:

> Stations will be asked whether they propose to render a well balanced program service, or to specialize in programs of a particular type addressed to a particular audience. If their proposal is for a specialized rather than a balanced program service a showing will be requested concerning the relative need for such service in the community as compared with the need for an additional station affording a balanced program service.[36]

Thus, the Commission recognized that a balanced service to listeners could be achieved either by a balanced program structure for each station or by means of a number of specialized stations that offered a balanced service to the community.

24. In 1949, the Commission issued its *Report on Editorializing by Broadcast Licensees,* 13 FCC 1246 (1949), which formalized the Fairness Doctrine and which again stressed, *inter alia,* the duty of all licensees to devote a "reasonable

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[23] 68 Cong. Rec. 4111.

[24] *1928 Annual Report to Congress by the federal Radio Commission,* page 161.

[25] 3 FRC Ann. Report 32 (1929).

[26] Davis, *The Law of Radio Communication, 1st Edition,* McGraw-Hill Book Company, Inc., New York, 1927, page 62.

[27] *Federal Communications Commission* v. *Pottsville Broadcasting Co., supra.*

[28] *See,* for example, S. Report No. 781 Committee on Interstate Commerce, U.S. Senate, 73rd Cong., 2d Session (1934).

[29] Although the Commission's regulatory activity relating to programming stems from the scarcity theory, neither the Commission nor the courts has ever scrutinized the validity or generality of that theory. Since we are reviewing Commission programming policies in this Notice, we must analyze the concept of scarcity that has been used. We shall perform this task at paragraphs 121–129, *infra.*

[30] The first major Commission policy statement on programming came in 1935, and involved non-profit programs.

[31] This "book" was issued as an internal Commission document and is available in the Commission's library.

[32] *Blue Book,* page 37.

[33] *Id.,* page 10.

[34] *Id.* at 13.

[35] *Ibid.*

[36] *Id.* at 58.

amount of time" to the discussion of public issues.[37] The Commission, however, still did not itself establish precise quantitative standards. Instead, it stated that "it is the licensee * * * who must determine what percentage of the limited boradcast day should appropriately be devoted to news and discussion or consideration of public issues, rather than to the other legitimate services of broadcast." [38] In the next decade, however, the Commission had little opportunity to apply these principles. There were only a very limited number of Fairness Doctrine complaints against broadcasters, and there were very few complaints or petitions alleging that a broadcaster had failed to provide programming responsive to public needs. It should be noted, however, that prior to *United Church of Christ* v. *F.C.C.*, 359 F. 2d 994 (D.C. Cir. 1966) the Commission believed that to be entitled to standing, petitioners would have to show a potential direct, substantial injury or adverse effect from the administrative action under consideration. This was primarily limited to instances where economic injury or electrical interference could be shown and thus limited the potential for the filing of such petitions.

25. Because of the limited case law, there was understandable confusion and uncertainty among broadcasters and public alike as to the precise nature of the broadcaster's public obligations. Accordingly, in 1960 the Commission issued its *Report re En Banc Programming Inquiry;* 44 FCC 2303 (1960) *(Programming Statement)*. The Commission stated that licensees must ascertain the needs and interests of their service areas and "reasonably attempt to meet all such needs on an equitable basis." Thus the licensee's obligation to operate in the public interest primarily involved its "diligent, positive and continuing effort * * * to discover and fulfill the tastes, needs and desires of his community or area for broadcast service."[39] It recognized, however, that "[p]articular areas of interest and types of appropriate service may, of course, differ from community to community, and from time-to time." Further, after listing fourteen "major elements [of programming] usually necessary to meet the public interest, needs and desires of the community,"[40] the Commission went on to say that these elements:

> Are neither all-embracing nor constant. We reemphasize that they do not serve and have never been intended to serve as a rigid mold or fixed formula for station operations. The ascertainment of the needed elements of the broadcast matter to be provided by a particular licensee for the audience he is obligated to serve remains primarily the function of the licensee. His honest and prudent judgments will be accorded great weight by the Commission. Indeed, any other course would tend to substitute the judgment of the Commission for that of the licensee.[41]

26. In the same document, the Commission also reasserted the inherent limitations of quantitative measurements. Quoting from a 1946 Public Notice, the Commission stated:

> It should be emphasized that the statistical data before the Commission constitutes an index only of the manner of operation of the stations and are not considered by the Commission as conclusive of the overall operation of the stations in question. Licensees will have an opportunity to show the nature of their program service and to introduce other relevant evidence which would demonstrate that in actual operation the program service of the station is, in fact, a well rounded program service.[42]

In short, although the licensee had a clear obligation to serve the public with programming responsive to local needs, the Commission left the licensee with broad discretion in deciding how to achieve that goal, stating that it did:

> * * * Not intend to guide the licensee along the path of programming; on the contrary, the licensee must find his own path with the guidance of those whom his signal is to serve.[43]

27. The licensee's discretion here was not unlimited. The Commission could not sanction programming decisions that discriminated against minorities.[44] Likewise, the Commission could not sanction a broadcaster's willingness to ignore "a strongly expressed need" that was or should have been known to it.[45] Many of the decisions on these points were not made until the late 1960's or 1970's. Earlier, however, broadcasters and citizen complaints about ambiguities in the *1960 Programming Statement* caused the Commission to further delineate the nature and scope of a broadcaster's obligation to ascertain community needs and to air informational programming responsive to those needs. The development of the ascertainment obligation is traced in the next section.

28. The Commission's policies on nonentertainment programming were further refined by the adoption of the Broadcast Bureau's current delegations of authority. On April 18, 1973, the Commission directed the staff to redraft these delegations of authority in terms of matters that had to be referred to the Commission. Prior to that time, the delegations of authority had enumerated specific powers that were delegated to the Chief of the Broadcast Bureau. As a result of the Commission's request § 0.281 of the Commission's Rules was redrafted to have the same basic structure and content as are in effect today, including the delegation with regard to levels of nonentertainment programming. (See, *Amendment of Part O of the Commission's Rules—Commission Organization—With Respect to Delegation of Authority to the Chief, Broadcast Bureau*, 43 FCC 2d 638 (1973).) Since the adoption of this revision, the only changes in § 0.281(a)(8)(i) have pertained to commercial television applications. (See, *Amendment to § 0.281 of the Commission's Rules: Delegations of Authority to the Chief, Broadcast Bureau*, 59 FCC 2d 491 (1976).) The delegations as applied to AM and FM radio, with regard to nonentertainment programming levels, have, however, remained the same since 1973.

C. The Development of Ascertainment Procedures

29. Even before the 1960 *Programming Statement* the Commission had alluded to the broadcaster's obligation to make a specific effort to understand the needs of his community.[46] The *Programming*

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[37] Interestingly, the Commission previously had been of the opinion that radio could not be used for advocacy, and therefore for the presentation of editorials. See, for instance, *Mayflower Broadcasting Corp.*, 8 FCC 333 (1940). In its *Report on Editorializing*, the Commission concluded that licensees could present the identified expression of their personal viewpoint as part of the "more generalized presentation of views or comments on various issues." The Commission had made a 180 degree turn to a policy that today seems farthest from radical.

[38] 13 FCC at 1247.

[39] 44 FCC at 2316.

[40] The listed elements are: (1) Opportunity for local self-expression, (2) the development and use of local talent, (3) programs for chileren, (4) religious programs, (5) educational programs, (6) public affairs programs, (7) editorialization by licensees, (8) political broadcasts, (9) agricultural programs, (10) news programs, (11) weather and market reports, (12) sports programs, (13) service to minority groups, and (14) entertainment programs. The Commission also concluded that there no longer was a public interest basis for distinguishing between sustaining and commercially sponsored programs in evaluating a station's performance. This constituted a major change in Commission policy toward programming.

[41] 44 FCC at 2314.

[42] 44 FCC at 2315–16.

[43] *Id.* at 2316.

[44] *Office of Communications of United Church of Christ* v. *FCC*, 425 F. 2d 543 (D.C. Cir. 1969); *Office of Communications of United Church of Christ* v. *FCC*, 359 F. 2d 994 (D.C. Cir. 1966); *Alabama Educational Television Commission*, 50 FCC 2d 461 (1975).

[45] *Stone* v. *FCC*, 466 F. 2d 316, 328 (D.C. Cir. 1972); *Alabama Educational Television Commission*, *supra*.

[46] *See e.g., P. B. Huff*, 11 FCC 1211, 1218 (1947); *Alexandria Broadcasting Corp.*, 13 FCC 601, 614 (1949); *Pilgrim Broadcasting Co.*, 14 FCC 1308, 1348

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Statement represented the first formal policy statement on the issue, however. Subsequent to the issuance of the *Statement*, the Commission proposed that broadcast applicants explain their efforts to identify community needs and to plan responsive programming.[47]

30. In the period between the adoption of the *program Statement* in 1960 and the amendment of the forms in 1965 and 1966, The Commission began implementing its policies. In 1961, the Commission denied an application for a new FM station in Elizabeth, New Jersey, on the ground that the applicant had not adequately ascertained community problems and needs. The Commission stated:

* * *It is not sufficient that the applicant will bring a first transmission service to the community—it must in fact provide a first local outlet for community self-expression. Communities may differ, and so may their needs; an applicant has the responsibility of ascertaining his community's needs and of programming to meet those needs (footnote omitted). The instant program proposals were drawn up on the basis of the principal's apparent belief—unsubstantiated by inquiry, insofar as the record shows—that Elizabeth's needs duplicated those of Alameda, California and Berwyn, Ill., (footnote omitted) or, in the words of the examiner, "could be served by FM broadcasters generally."* * * [T]he evidence admits no other conclusion than that the applicant's program proposals were not "designed" to serve the needs of Elizabeth * * * [T]he applicant has made no showing as to Elizabeth's programming needs, and a determination of whether Suburban's program proposals "would be expected" to meet such needs is rendered impossible. In essence, we are asked to grant an application prepared by individuals totally without knowledge of the area they seek to serve. We feel that the public deserves something more in the way of preparation for the responsibilities sought by [the] applicant than was demonstrated on this record.[48]

31. The applicant raised statutory and constitutional objections to the decision on appeal. The Court rejected the objections as follows:

As we see it, the question presented on the instant record is simply whether the Commission may require that an applicant demonstrate an earnest interest in serving a local community by evidencing a familiarity with its particular needs and an effort to meet them. We think *National Broadcasting Co.*, v. *United States*, 319 U.S. 190, 63 S. Ct. 997, 87 L. Ed. 1344 (1943), settles the narrow question before us in the affirmative. There, the Commission promulgated regulations which provided, *inter alia*, that no license be granted to stations whose network contracts would prevent them from developing programs "to serve the needs of the local community." 319 U.S. at 203. National Broadcasting Company challenged the regulations on precisely the grounds appellants advance here: That since the regulations were calculated to affect program content, they exceeded statutory and constitutional limitations. In sustaining the regulations, the Supreme Court held the Commission may impose reasonable restrictions upon the grant of licenses to assure programming designed to meet the needs of the local community. We think it clear that the Commission's action in the instant case reflects no greater interference with a broadcaster's alleged right to choose its programs free from Commission control than the interference involved in *National Broadcasting Co.* [footnote omitted].[49]

32. When the new application forms were adopted in 1965 and 1966, the Commission imposed a four-step ascertainment process. Applicants were expected to provide full information on the following matters:

(a) The steps taken to become informed of the problems and needs of the area to be served;

(b) The suggestions received as to how the station could help meet those problems and needs;

(c) The applicant's evaluation of the suggestions; and,

(d) The programming proposed to meet evaluated problems and needs.[50]

These changes were soon reflected in the Commission's actions. Issues were added in hearings [51] and petitions to deny applications raised questions about compliance with the ascertainment requirements.[52] The Commission, perceiving a problem, issued a Public Notice [53] to publicize its requirements and to lessen a "costly workload burden on the Commission." [54] The Commission later made another change. It ruled that the applicant's subjective evaluation of the ascertained problems and needs must be made, but that it need not be submitted as part of the application.[55]

33. Considerable problems remained over the precise nature of the Commission's requirements. In *City of Camden*,[56] the Commission denied an application for assignment of license because the assignee had not adequately ascertained community problems. Among the shortcomings described in the Commission's decision was the fact that the community leaders canvassed did not appear to reflect a cross-section of the community when compared to known demographic information.[57]

34. Motivated in part by the *City of Camden* decision, the Federal Communications Bar Association asked for clarification. As a consequence, the Commission initiated a Notice of Inquiry in which it proposed a detailed ascertainment primer.[58] A primer containing 36 questions and answers was adopted after consideration of the many comments filed in that proceeding.[59] The Commission set out procedures for determining the composition of the area to be served, consultations with community leaders and members of the general public, enumeration of community problems and needs, evaluation of the problems and needs,[60] and relating proposed programming to the evaluated problems and needs. Failure to conduct the ascertainment in accordance with the requirements of *The Primer* has resulted in the denial of applications. Such denials have been upheld in court.[61]

35. *The Primer* was applicable at the outset to all applicants. On the same day, however, that *The Primer* was issued, another proceeding was initiated to determine whether different standards should be applicable to renewal applicants. A *Renewal Primer*, with different standards, was ultimately adopted.[62] The four basic requirements in the original primer were retained for renewal applicants. Procedurally, though, the *Renewal Primer* made some changes:

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(1950); *Mid-Island Radio, Inc.*, 15 FCC 617, 640 (1951); and *Wayne M. Nelson*, 44 FCC 1132, 1136 (1957).

[47] The forms were not amended until 1965 for radio and 1966 for television. *AM and FM Program Form*, 1 FCC 2d 439 (1965); *Television Program Form*, 5 FCC 2d 175 (1966).

[48] *Suburban Broadcasters*, 30 FCC 1021, 1022–23 (1961).

[49] *Henry* v. *FCC*, 302 F. 2d 191, 193–94 (D.C. Cir. 1962), *cert. denied*, 371 U.S. 821 (1962)

[50] *Television Program Form, supra*, 5 FCC 2d at 178.

[51] *See, Minshall Broadcasting Co.*, 11 FCC 2d 796 (1968)

[52] *See, Andy Valley Broadcasting System.* Where the Commission stated: "The new form now makes a program survey mandatory. Applicants, despite long residence in the area, may no longer be considered, *ipso facto*, familiar with the programming needs and interests of the community." 12 FCC 2d 3, 6 (1968).

[53] 13 RR 2d 1903 (1968).

[54] *Id.*

[55] *Sioux Empire Broadcasting Co.*, 16 FCC 2d 995 (1969).

[56] 18 FCC 2d 412 (1969).

[57] *Id. at 422.*

[58] 20 FCC 2d 880 (1969).

[59] *Ascertainment of Community Problems*, 27 FCC 2d 650 (1971).

[60] The word "evaluation" as used in *The Primer* means the process in which the licensee: considers the ascertained problems and needs of its area; considers the characteristics of that area, the characteristics of its specific audience, and its own skills and resources to determine which problems and needs it should serve; and, decides upon the programming that will be most responsive to those problems and needs. *See, generally, Ascertainment of Community Problems*, 27 FCC 2d at 671–74.

[61] *E.g., Bamford* v. *FCC*, 535 F. 2d 78 (D.C. Cir. 1976).

[62] *Ascertainment of Community Problems by Renewal Applicants*, 57 FCC 2d 418 (1975), *recon. granted in part*, 61 FCC 2d 1 (1976).

(a) It calls for an on-going process, rather than conducting ascertainment solely in the six months preceding the filing of the renewal application;

(b) It provides a community leader "checklist;"

(c) It specifies the number of consultations to be made, based on the size of the city of license;

(d) It requires renewal applicants to maintain information on the composition of their communities in their public inspection file, but they are not required to compile such information separately for each successive renewal application filed;

(e) It requires that licensees annually deposit in their public inspection files a list of no more than ten problems and needs existing in their service areas during the preceding year, and a list of programs treating those problems and needs; and,

(f) It requires documentation of ascertainment procedures to be placed in the station's public inspection file.[63]

36. The *Renewal Primer* experimentally created a partial "small-market" exemption for stations licensed to certain cities of 10,000 or less on the ground that the licensees of small communities should know the problems and needs without formal ascertainment requirements.[64] The exemption, however, does *not* relieve small-market licensees from the duty to respond to the problems and needs of their communities.

37. In general, although they have provided very specific guidance for and oversight of broadcasters, the ascertainment primers carried over three basic principles of broadcast regulation. First, the Primers made it clear that the broadcaster has broad discretion. The *Primer* stated that:

> There is no single answer for all stations. The time required to deal with community problems can vary from community to community and from time to time within a community. Initially, this is a matter which falls within the discretion of the applicant.[65]

Similarly, the *Renewal Primer, supra,* declared:

> It is the responsibility of the individual licensee to determine the appropriate amount, kind and time period of broadcast matter which should be presented in response to the ascertained problems, needs and interests of its community and service area.[66]

38. Second—and of major importance for present purposes—the primers acknowledged that a broadcaster could take into account its particular audience and the programming of other stations in the market in making programming decisions. The Commission did clearly state that a broadcaster could not ignore a community problem simply because few in the broadcaster's audience shared that problem.[67] By the same token, the Commission said the make-up of the audience and market were relevant factors:

> Answer 25 does rest on the applicant's good faith determination (in making programming decisions), which, of course, gives him considerable discretion. Thus, he may choose to meet as many problems as he believes he can. He may be selective, giving more extensive treatment to those problems he believes most important or to nascent problems, which if not met now are likely to become critical. Or he may recognize that another station in the community traditionally presents extensive broadcast matter to meet a particular problem. If it is an important problem, and if the stations' respective audiences differ only slightly in their composition, the broadcaster may decide to present some broadcast matter to meet the problem, but less than he would ordinarily due to the efforts of the other station.[68]

Similar language was included in the 1976 *Renewal Primer:*

> In making this (programming) determination, the licensee may consider the programming offered by other stations in the area as well as its station's program format and the composition of its audience. With respect to the latter factor, however, it should be borne in mind that many problems affect and are pertinent to diverse groups within the community. All members of the public are entitled to some service from each station. While a station may focus relatively more attention on community problems affecting the audience to which it orients its program service, it cannot exclude all other members of the community from its ascertainment efforts and its nonentertainment programming.[69]

In other words, other stations' programming and audience make-up could influence the broadcaster's programming judgment; but those factors could not justify totally disregarding a problem.[70]

39. Third, the Commission retained the right to inquire about the basis for a licensee's programming choices; and if the licensee's actions were unreasonable or made in bad faith, we made it clear that further actions—including denial of a license application—could result. As we said in the 1971 *Primer:*

> [W]here the amount of broadcast matter proposed to meet community problems appears patently insufficient to meet significantly the community's problems disclosed by the applicant's consultations, he will be asked for an explanation by letter of inquiry from the Commission.[71]

Similarly, the 1976 *Renewal Primer* states:

> Where the licensee * * * has chosen a brief and unusually superficial manner of presentations, such as news and public service announcements, to the exclusion of all others, a question could be raised as to the reasonableness of the licensee's action. The licensee would then be required to clearly demonstrate that its single type of presentations would be the most effective method for its station to respond to the community's ascertained problems.[72]

40. In essence, then, the Commission allows the broadcaster to consider his individual circumstances and make his own choices—unless these appear to be unreasonable.

Commercial Practices

41. The Commission's concern with commercial practices has been marked by two basic features: A desire to prevent use of scarce broadcast time primarily to advertise private interests, and a refusal to adopt definitive standards. Hence, while the Commission has always closely scrutinized a licensee's commercial practices, the Commission has not specified any outer limit which no licensee can ever transcend. It is also noteworthy that, in making decisions on individual license applications, the Commission has almost always viewed commercial practices from the perspective of an individual broadcaster; rarely has the Commission justified its conclusion by reference to general market conditions.[73]

42. Concern about the commercial practices of broadcast stations goes back more than 50 years. In *Great Lakes Broadcasting Company,* the Federal Radio Commission stated: "Advertising

[63] 47 CFR 73.3526(a)(11) and (12).

[64] *Ascertainment of Community Problems by Renewal Applicants, supra,* 57 FCC 2d at 437. Noncommercial applicants are not the subject of this proceeding. However, it should be noted that ascertainment requirements have been imposed upon noncommercial applicants. *Ascertainment of Community Problems by Noncommercial Applicants,* 58 FCC 2d 526 (1976).

[65] 27 FCC 2d at 686.

[66] 57 FCC 2d at 445.

[67] 27 FCC 2d at 673.

[68] *Id.*

[69] 57 FCC 2d at 445.

[70] In some respects, the language of the primers, in retrospect, seems inconsistent. On the one hand, the Commission stated that the broadcaster need not respond to all community problems and that he should use his good faith judgment in selecting problems; on the other hand, the Commission appeared to be saying that a broadcaster's choice of problems must be such as to reach everyone in the community to some extent.

[71] 27 FCC 2d at 686.

[72] 57 FCC 2d at 445.

[73] It should be noted, however, that our processing guidelines do account, in a limited way, for the market conditions in which licensees operate. As noted below, our processing guidelines distinguish between seasonal and nonseasonal markets.

must be accepted for the present as the sole means of support for broadcasting, and regulation must be relied upon to prevent abuse or overuse of the privilege." [74] The Commission took actions that also reflected concern about commercial practices. Based on proposed or past commercial practices, the Commission has denied applications,[75] conducted hearings on renewal applications,[76] considered commercial practices in comparing mutually exclusive applications,[77] and granted short-term renewals.[78] In the earlier cases, the phrase "commercial practices" included the number of spot announcements or program interruptions, the length of individual announcements, and the balance between "commercial" (sponsored) programs and "sustaining" (nonsponsored) programs, as well as the total amount of commercial time.[79]

43. In 1960, the Commission summarized its policy as follows:

"With respect to advertising material, the licensee has the additional responsibility * * * to avoid abuses with respect to the total amount of time devoted to advertising continuity as well as the frequency with which regular programs are interrupted for advertising messages." [80]

There were, however, no standards by which to judge compliance with that policy and the cases cited in the preceding paragraph were case-by-case rulings. As a consequence, E. William Henry, then Chairman of the Commission, testified before the House Committee on Interstate and Foreign Commerce in 1963, that he, "did not know and no one could know" what the Commission's policy on overcommercialization was.[81]

44. Chairman Henry's words came during Congressional testimony concerning a Commission rulemaking proceeding proposing commercial standards.[82] The Commission's proposal received strong opposition. In fact, the House, but not the Senate, passed legislation (H.R. 8316) in 1963 that would have prohibited any Commission rule that prescribed "standards with respect to the length or frequency of advertisements which may be broadcast by all or any class of stations in the broadcast services." [83] The Commission later decided not to adopt a rule in light of the opposition, the absence of certain information believed necessary for an informed judgment, and growing industry efforts at self-regulation.[84] The Commission did, however, warn broadcasters that the Commission would still closely watch commercial practices:

We emphasize that we will give closer attention to the subject of commercial activity by broadcast stations and applicants on a case-by-case basis. Thus, we will continue to require station applicants to state their policies with regard to the number and frequency of commercial spot announcements as well as their past performance in these areas. These will be considered in our overall evaluation of station performance.[85]

45. The case-by-case approach still presented problems.[86] New administrative tools, however, began to be employed. In *Florida Renewals*,[87] the Commission granted the renewal applications of stations that had heavy commercial loads, but asked for a follow-up report on the number of complaints received, the number of times the licensees exceeded 18 minutes of commercial matter per hour, and a statement as to why its commercial policies were consistent with the public interest. In *WDIX Inc.*, the Commission found that a renewal applicant had "failed to show that [its] policy serves the needs and interest of [its] service area." [88] Further information was sought from the applicant.

46. In 1970 the Chief of the Broadcast Bureau, with the approval of the Commission, sent a letter to Peoria Valley Broadcasting, Inc., licensee of Station WXCL. The letter was never published, but became a processing standard for the staff. It stated that the licensee's commercial policy "would obviate any problem with the commercial aspects of your operation at the next renewal period." That commercial policy specified:

* * * a normal commercial content of 18 minutes in each hour with specified exceptions permitting up to 20 minutes in each hour during no more than 10% of the total weekly hours of operation. A further exception would permit up to 22 minutes where the excess over the 20-minute ceiling is purely political advertising.[89]

The standards set out in the WXCL letter were later incorporated in the rules setting out the authority delegated to the Chief of the Broadcast Bureau.[90] In 1976, by Public Notice, the 22-minute exception was expanded by 4 minutes during 10 percent of the broadcast hours in periods when lowest-unit-charge requirements are applicable to the broadcast of political advertising.[91] The present delegation of authority with respect to commercial policy is set out below.[92]

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[74] Reported at 3 FRC Ann. Rep. 32, 35 (1929), *aff'd* 37 F.2d 993 (D.C. Cir. 1930) *cert. den.* 281 U.S. 706 (1930).

[75] *R. R. Jackson*, 5 FCC 496 (1938); *Travelers Broadcasting Service Corporation*, 6 FCC 456 (1938).

[76] *The Community Broadcasting Co.*, 12 FCC 85 (1947); *The Walmac Co.*, 12 FCC 91 (1947); and *Michigan Broadcasting Co.*, 20 RR 667 (1960).

[77] Sheffield Broadcasting Co., 30 FCC 579 (1961); *Fischer Broadcasting Co.*, 30 FCC 177 (1961).

[78] *Gordon Country Broadcasting Co.*, 24 RR 315 (1962).

[79] For more information on the balance between commercial and sustaining programs, and the background and development of Commission policies on advertising, *see* pp. 29–57 and 73–89 of *The Blue Book*.

[80] *Programming Statement*, 44 FCC at 2313.

[81] *H. R. Rep. No. 1054*, 88th Cong., 1st Sess. 24 (1963).

[82] The Notice of Proposed Rule-Making is published at 28 Fed. Reg. 5158 (1973).

[83] *H. R. Rep. No. 1054*, *supra*, at 9.

[84] *Commercial Advertising*, 36 FCC 45 (1964). Although it declined to adopt a rule, the Commission did assert that it had ample authority to adopt one, a point that had been contested by many of the parties filing comments in the proceeding. The decision was followed by a memorandum from the General Counsel supporting Commission authority to adopt such a rule (36 FCC at 50–61).

[85] *Id.* at 49–50.

[86] *Commercial Practices of Broadcast Licensees*, 2 RR 2d 885 (1964) (Chairman Henry dissenting).

[87] 9 RR 2d 639 (1967).

[88] 14 FCC 2d 265 (1968).

[89] Note that by this time the Commission's concern was directed solely to the total amount of commercial matter broadcast per hour. The number of interruptions was not mentioned in the WXCL letter. The balance between sponsored and nonsponsored (sustaining) programs had been dropped from Commission considerations with the adoption in 1960 of the *Programming Statement*, *supra*, where the Commission observed at p. 2315, "* * * sponsorship fosters rather than diminishes the availability of important public affairs and 'cultural' broadcast programming." The Commission has ruled, however, that the broadcast of a commercial message lasting 15 or more minutes is contrary to the public interest. *See, for example, KCOP–TV Inc.*, 24 FCC 2d 149 (1970); *Weigel Broadcasting Co.*, 41 FCC 2d 370 (1973); *Program-Length Commercials*, 44 FCC 2d 985 (1973).

[90] *Delegation of Authority*, 43 FCC 2d 638 (1973).

[91] *Political Spot Announcements on Radio*, 59 FCC 2d 103 (1976). Under 47 U.S.C. 315(b)(1), qualified candidates for public office must be accorded the licensee's lowest unit charge for use "during the forty-five days preceding the date of a primary or primary runoff election and during the sixty days preceding the date of a general or special election."

[92] 47 CFR § 0.281(a)(7) provides that the Chief of the Broadcast Bureau may not grant applications exceeding the following criteria:

(i) Commercial AM and FM proposals in non-seasonal markets exceeding 18 minutes of commercial matter per hour, or providing for exceptions permitting in excess of 20 minutes of commercial matter per hour during 10 percent or more of the stations' total weekly hours of operation.

(ii) Commercial AM and FM proposals in seasonal markets (e.g., resort markets) exceeding 20 minutes of commercial matter per hour during 10 percent or more of the stations' total weekly hours of operation.

(iii) During periods of high demand for political advertising proposals exceeding either (a) an additional 4 minutes per hour of purely political advertising or (b) exceeding 10 percent of the station's total hours of operation in the applicable lowest-unit-charge period.

(iv) Commercial TV proposals exceeding 16 minutes of commercial matter per hour, or, during periods of high demand for political advertising, providing for exceptions permitting in excess of 20 minutes of commercial matter per hour during 10

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47. The Commission has issued prehearing letters in cases where licensees have proposed commercial policies that greatly exceed the guidelines set out in the delegations of authority to the Chief of the Broadcast Bureau. For example, in *Marion Broadcasting Co.,*[93] the Commissions stated:

* * * approval of the guidelines set forth in § 0.281(a)(7) of the rules does not foreclose the right of each broadcaster to make a different judgment on any reasonable basis in light of its particular situation. We recognize that special circumstances may warrant adoption of different commercial policies. However, the Commission—which reviews *en banc* all applications proposing to exceed the commercial guidelines summarized above—has found that policies exceeding the guidelines serve the public interest only when evidence clearly indicates that such policies are essential to maintain service to the public. At present, you have produced no such evidence.

* * * * *

* * * [Y]ou are given this final opportunity to provide a meaningful justification for your commercial proposal or amend your application to conform to Commission guidelines in this area. If you fail to do so, it will be necessary to designate your application for hearing to determine whether your proposal would serve the public interist.[94]

48. Licensees that exceed the proposals submitted to the Commission have been granted short-term renewals [95] or admonished,[96] depending on the circumstances.

49. There have been few court cases on the subject. In *Bay State Beacon* v. *FCC,* the Court held that the Commission, in a comparative proceeding, may properly inquire "into the amount of sustaining time a prospective licensee purports to reserve if granted a license." [97] In another comparative proceeding, while on appeal, the Court asked the Commission to respond to several questions, including the following:

1. Is the amount of TV time actually used in stating, singing or otherwise showing commercials a public interest consideration?

2. If so, should the Commission be required to consider the length and number of commercials proposed by the competing applicants in this case? [98]

In its supplemental brief submitted in response to these questions, the Commission stated:

The amount of time devoted by television broadcast stations to advertising messages is one of the factors which the Commission may properly consider, and may assume significance in the public interest judgment in particular circumstances. The governing statute, decisions of the courts, and Commission precedent make this amply clear.[99]

The Commission urged that the circumstances of the case did not warrant remand for consideration of the commercial practices of the applicants. The case was not remanded, and the Commission's award of a construction permit to one of the applicants was affirmed. Other than to note the Commission's response, the matter was not further discussed by the majority of the panel,[100] although the dissenting judge did briefly comment on the matter.[101] Later, however, in *Citizens Communications Center* v. *FCC,* the Court stated that the "elimination of excessive and loud commercials" was one of several tests of "superior service" in comparative hearings between new and renewal applicants.[102]

50. In sum, although the Commission may and does review the commercial practices of licensees, the Commission has not adopted rigid rules. Nor has the Commission foreclosed the possibility that competitive market conditions may, under some circumstances, render the Commission's scrutiny unnecessary.

III. A Reevaluation of Our Current Regulatory Approach in Light of Changed Circumstances

A. Our Interpretation of the Public Interest

51. It was clear from the very beginning of broadcasting that radio was a rapidly developing medium. Accordingly, Congress' efforts to legislate in the area were complicated by the need to write a law at a fixed point in time that would be sufficiently flexible to allow for this quickly changing technology and industry. Therefore it couched the Commission's regulatory authority in terms of the public interest, convenience and necessity. Thus, the Commission was given neither unfettered discretion to regulate all phases of radio nor an itemized list of specific manifestations that it could or should regulate. As the Supreme Court has said, to have done otherwise:

* * * would have stereotyped the powers of the Commission to specific details in regulating a field of enterprise the dominant characteristic of which was the rapid pace of its unfolding. And so Congress did what experience had taught it in similar attempts at regulation, even in fields where the subject-matter of regulation was far less fluid and dynamic than radio. The essence of that experience was to define broad areas for regulation and to establish standards for judgment adequately related in their application to the problems to be solved.[103]

52. It has been said that the term "public interest" cannot be defined by legislation.[104] It is well settled, however, that the term was not unconstitutionally vague when applied to the Radio Act and, acccordingly, met constitutional requirements when it was included in the Communications Act.[105] The term has been described as providing the "fullest and most effective use," of radio frequencies and to "* * * be interpreted by its context, by the nature of radio transmission and reception, and by the scope, character and quality of services* * *" [106] It also has been described as "* * * the interest of the listening public in the larger and more effective use of radio."[107] Thus, it is our task to ensure through our rules, policies and decisions, that the radio frequency spectrum is given the largest and most effective use for the benefit of the public.

53. The question, then, arises as to whether or not, based on significant changes in the broadcasting industry and in the market place in which it operates, we can, consistent with our public interest mandate, undertake the radical departure from prior and current Commission rules and policies proposed herein. That question has consistently been answered in the affirmative by courts and by our own actions. The Supreme Court has recognized that:

[U]nderlying the whole law [of communications] is recognition of the rapidly fluctuating factors characteristic of the evolution of broadcasting and of the corresponding requirement that the administrative process possess sufficient flexibility to adjust itself to these factors.[108]

This flexibility permits Commission reassessment of the public interest, even

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percent or more of the station's total weekly hours of operation.

[93] 44 RR 2d 1045, 1056 (1978).

[94] *Id.* at 1046–47.

[95] *Enid Radiotelephone Co.*, 67 FCC 2d 19 (1977).

[96] *CBS, Inc.*, 41 RR 2d 1350 (1977); *Chattahoochie Broadcasting Company*, 69 FCC 2d 1460 (1978).

[97] 171 F. 2d 826, 827 (D.C. Cir. 1948).

[98] *South Florida Television Corp.* v. *FCC*, 4 RR 2d 2048 (D.C. Cir. 1965).

[99] Supplemental Brief, p. 2, Case Nos. 18,873 and 18,880, in the United States Court of Appeals for the District of Columbia Circuit.

[100] *South Florida Television Corp.* v. *FCC*, 349 F. 2d. 971 (D.C. Cir. 1965).

[101] *Id.* at 973.

[102] 447 F. 2d. 1201, 1213, n. 35 (D.C. Cir. 1971).

[103] *National Broadcasting Company* v. *United States*, 319 U.S. 190, 219–20 (1943).

[104] Davis, *supra.*, Note 26, page 59.

[105] *White* v. *Federal Radio Commission*, 29 F. 2d 113 (N.D. Ill.1928).

[106] *National Broadcasting Co.*, v. *United States*, *supra.*, page 218.

[107] *Id.* at 216.

[108] *Federal Communications Commission* v. *Pottsville Broadcasting Co.*, *supra.*, Note 16, page 138.

if it means a complete reversal of prior policies. As Judge E. Barrett Prettyman wrote:

And it is also true that the Commission's view of what is best in the public interest may change from time to time. Commissions themselves change, underlying philosophies differ, and experience often dictates changes. Two diametrically opposite schools of thought in respect to the public welfare may both be rational; e.g., both free trade and protective tariff are rational positions. All such matters are for the Congress and the executive and their agencies.[109]

54. More recently, it has been stated that an agency's view of what is in the public interest may change even absent a change in circumstances, provided that it supplies a reasoned analysis indicating that its change of prior policies was deliberate.[110] Thus, the public interest is a "supple instrument" providing the flexibility to deal with changing circumstances and philosophies.[111]

55. We have never hestitated to change policies and rules when they cease to be required by the public interest. For instance, as noted above, for some fifteen years, the Commission maintained a policy prohibiting editorials by radio licensees. Once we determined, however, that such a ban no longer served the public interest, we changed our policy and permitted such editorializing.[112] Similarly, for many years the Commission believed that "sustaining" programs were essential to service in the public interest. Yet, once we concluded that conditions no longer warranted distinguishing between sustaining and sponsored programs in evaluating stations' performances, we did not hesitate to reverse our prior course.[113] Simply, the settled case law does not require that we retain rules and policies *ad infinitum* and it has consistently been our practice to discard unneeded regulations.

56. In view of our forty-five years of experience in regulating broadcast radio, mindful of the legislative history of the Communications Act and our rules and policies as noted above, and in light of the data set forth below, we believe that it is appropriate for the Commission to initiate substantial deregulation of broadcast radio. We note that circumstances have changed greatly since 1927. At that time there were but 681 broadcast radio stations.[114] As of July 31, 1979, 8,654 such stations were comprised of 4,547 AM stations, 3,114 commercial FM stations, and 993 educational FM stations.[115] This increase in stations has been steady and dramatic. For instance, when the *Blue Book* was issued there were 931 AM and 46 FM stations licensed.[116] By the time of the *En Banc Programming Inquiry* report the number had grown to 3,581 AM stations, 912 commercial FM stations, and 181 educational FM stations for a total of 4,674 broadcast stations.[117] And this was nearly 4,000 fewer radio stations that are licensed today. Additionally, since the advent of modern broadcast regulation, alternative sources of informational programming have arisen such as commercial television, public television, and cable television.[118]

57. Traditionally, we have carried out our public interest mandate primarily by means of conduct related regulation. The First Amendment implications of such regulation have placed us in the difficult position of attempting to promote specific types of programming while at the same time avoiding supplanting of licensee discretion with the Commission's programming views. In addition to the content related approach, the Commission has also sought to achieve program diversity through structural means. Notable examples include our multiple ownership rules, which foster diversity of voices by limiting the number of outlets that any one source can control; our EEO and minority ownership rules and policies, which foster increased minority representation in the workforce and ownership of broadcast stations, thereby increasing the diversity of voices represented in broadcasting; and our efforts to increase or more efficiently use the broadcast radio spectrum, including the 9 kHz. proceeding, BC Docket No. 79-164, (FCC 79-395), the Clear Channel proceeding, Docket No. 20642, and our proposal to the 1979 World Administrative Radio Conference that the AM band be expanded. We believe that in the future the emphasis of our regulatory effort should be shifted away where possible from content regulation and towards these types of structural vehicles. To do otherwise would continue to embroil unnecessarily the Commission in questions of what is, and is not, good or desirable radio programming.

58. This does not mean that we must await further structural diversity prior to taking the deregulatory steps that we are proposing today. Significant diversification in the communications industry has already taken place. The advent and growth of FM radio, noncommercial broadcasting, and television have all contributed to broadcast diversification since the early days of radio. Efforts to promote minority ownership [119] and EEO are underway and promise to bring about a more demographically representative radio industry.

59. It is of the highest importance that we begin to chart the course of the Commission's regulatory activity for the foreseeable future. In the context of commercial AM and FM broadcasting, the course that appears in the public interest is the one that permits the market to dictate the programming decisions while the Commission regulates the structural aspects of that medium.

60. In that regard we recognize with reference to commercial radio that our views of what is desirable programming may be no better, more perceptive, or wiser than those of our licensees and the general public which they serve. In fact, it has been argued that our decisionmaking in such matters may even place the Commission between the licensee and the public he serves, to some extent insulating the licensee from his community and leading to the result that the licensee responds to the programming preferences of the Commission rather than to those of the local audience.[120] In the past we have tried to assure that radio broadcasters meet the demands of their service area by imposing a panoply of programming

[109] *Pinellas Broadcasting Company* v. *Federal Communications Commission*, 230 F. 2d 204, 206 (D.C. Cir. 1956), *cert. denied* 76 S. Ct. 650 (1956).

[110] *Greater Boston Television Corp.* v. *Federal Communications Commission*, 444 F. 2d 841, 852 (D.C. Cir. 1970), *cert. denied*, 403 U.S. 923 (1971).

[111] *Federal Communications Commission* v. *Pottsville Broadcasting Co., supra.*, Note 16, page 138; also see, *Columbia Broadcasting System, Inc.* v. *Democratic National Committee*, 412 U.S. 94, 102 (1973).

[112] See Note 37, *Supra*.

[113] See Note 89, *supra*.

[114] See Paragraph 14, *supra*.

[115] Public Notice No. 20353, released August 14, 1979.

[116] *16th Annual Report of the Federal Communications Commission*, page 102.

[117] *27th Annual Report of the Federal Communications Commission*, page 58.

[118] At the same time, another major alternative information source, newspapers, has declined in number. While there were 1,949 daily and 526 Sunday newspapers in 1927, as of March 30, 1978, there were 1,753 daily and 668 Sunday newspapers. See Note 19, *supra.*, and Bureau of the Census, *Statistical Abstract of the United States: 1978 (99th Edition)*, Wshington, D.C. 1978, page 597. Thus, newspapers are presently as scarce in relation to radio stations as radio stations were in relation to newspapers in 1927. In 1927, there were approximately 3.5 newspapers (daily and Sunday) to each broadcast radio station while now the figures are almost exactly reversed.

[119] *See, Statement of Policy on Minority Ownership of Broadcasting Facilities*, 68 FCC 2d 979 (1978).

[120] *See* Goldberg and Couzens, *"Peculiar Characteristics": An Analysis of the First Amendment Implications of Broadcast Regulation*, Federal Communications Law Journal, Vol. 31, No. 1, Winter, 1978.

requirements.[120A] Given the circumstances described above and the data and analysis provided below, we believe that the public interest is best served by reducing our involvement in programming decisions in broadcast radio and substituting the public will through the workings of marketplace forces.

61. As the foregoing history shows, we realize that the rule changes proposed here concern basic matters of Commission law and policy. We also recognize that we have an obligation to explain and justify any proposed departures from present rules and policies.[121] There is a considerable body of evidence and theory that strongly suggests that the proposed changes will serve the public interest—that the discipline imposed by market forces upon licensees will result in greater responsiveness to consumer preferences than regulatory guidelines can provide.

62. We are mindful of the seriousness of the proposed undertaking, but we also are aware that existing policies and rules are but means to attain public interest objectives and are not immutable. As noted above, when circumstances change, the effectiveness of these policies and rules may also change. In this proceeding we are reassessing some of our rules and policies in light of major technological and social changes.

63. In the next subsection of this Notice we present evidence of structural changes in the radio industry and American society that prompt our re-evaluation of Commission rules and policies. We then provide an economic policy framework in which to analyze both the existing rules and proposed changes. Finally we apply that analytical framework to the radio market as it exists today, and conclude that, on balance, the available empirical evidence supports the proposed policy changes. Public comment is solicited on the soundness of the theory as well as the validity of the facts and assumptions presented.

B: Structural Changes in Radio Markets

Growth in the number of stations

64. Technological advances and increased demand have resulted in substantially greater use of the AM and FM radio spectrum. As noted above, in 1934 there were 583 AM stations and no FM stations on the air. Today there are 8,654 broadcast radio stations, 4,547 AM and 4,107 FM.[122] Table 1 shows the dramatic growth in radio stations in operation. This growth represents both an extension of radio service into previously unserved rural areas and a substantial increase in the number of stations in existing urban markets. Table 2 shows the increase in the number of radio stations over time for a sample of urban markets.[123] Table 3 shows the number of stations currently in operation in markets with eight or more stations. It should be noted that 17 markets have 30 or more radio stations; 46 have 20 or more; and 137 have 10 or more.

65. As Table 1 indicates, the growth in the number of radio stations in recent years has been most dramatic in the FM band. Technological improvements in transmission and reception and the development of FM stereo have been instrumental in this growth. FM initially suffered two disadvantages—there were relatively few radio receivers with FM capability, and for a given transmitter power FM signals cannot be transmitted as far as AM signals. The advent of television, however, has partially changed the role of radio. Instead of being a "common denominator medium" reaching for a broad audience, radio, especially in the larger markets, has increasingly become a specialty medium reaching for a narrower audience. In this newer role, FM is no longer at a disadvantage with AM. In fact, FM can exploit its own technical advantages over AM, such as superior sound quality.[124]

66. There is considerable evidence that FM radio has now attained competitive parity with AM. The October/November, 1978 Arbitron sweep data show, at least in the approximately 100 largest markets, many FM stations are equal competitors with AM stations. The fall 1978 and earlier Arbitron data have been available for analysis to many parties and a consensus has been reached that there is a strong trend toward FM parity. An article in the February 26, 1979, *Television/Radio Age* magazine presents considerable Arbitron data and reports that "more than half of the leading metro stations in the fall [1978] Arbitron Radio sweep were FM outlets * * *."[125] An article in the January 22, 1979, *Broadcasting* magazine provides both compilations of Arbitron data and anecdotal evidence in support of the contention of FM parity.[125A] That article indicates that in each of the top 50 markets at least 4 of the top 10 stations are FM. Thus, in Washington, D.C., 8 out of the top 10 stations are FM; in Dallas and Philadelphia, 7 out of the top 10 are FM; and the respective numbers are 6 in Pittsburgh, and 5 in New York, Chicago, Los Angeles and Detroit. In addition to the rating data, the *Broadcasting* article provided anecdotal information on the prices of recent FM stations sales. For example, contingent on FCC approval, the buyers of KBPI (FM) in Denver reportedly will pay $6.7 million.

67. Another indication of FM's improving status is that, while the number of independent FM stations reporting data to the FCC increased less than 5% (from 713 to 741) between 1976 and 1977, during the same period their combined reported profits more than doubled (from $4.3 million to $9.4 million). Similarly, the number of reporting FM stations associated with AM stations increased from 562 to 586 while their reported profits rose from $16.9 million to $32.2 million.[126] These data provide strong evidence that FM radio is now a viable and profitable competitive force.

68. The growth of a viable FM presence has important policy implications. The data in Table 1 listing the number of stations on the air might be meaningless, if, for example, all or most of the new stations were marginal and provided little actual or potential competition to powerful AM stations. In that case, the latter could simply disregard the fringe stations and be slow to adapt to changing conditions. On the other hand, if the new stations can and do capture significant audience shares from existing stations, then the older dominant stations must be responsive to the challenge of competition. If successful, innovative stations with experimental formats would place strong competitive pressures on existing stations, and would affect market conduct and performance.

[120A] *See, for instance,* the *En Banc Programming Inquiry* report, *supra.,* pages 2311, 2312.

[121] See, *Greater Boston Television Corp.* v. *F.C.C.,* 444 F. 2d 841, 852 (D.C. Cir. 1970), *cert. denied,* 403 U.S. 923 (1971).

[122] See paragraph 56, *supra.*

[123] The sample was chosen by listing all markets in descending order by size (defining size as the number of stations in the markets), randomly choosing one of the 15 largest markets, and then choosing every subsequent fifteenth market. Where there was more than one market with the same number of stations, the particular market used in the sample was randomly selected.

[124] FM also used other methods to gain competitive parity with AM, such as reduced commercial time. To the extent that FM success was a function of this strategy, it suggests that stations might rationally choose to reduce commercial minutes to gain audience and, in the long run, profits. This will be discussed in greater detail below.

[125] "FM stations comprise more than half of leaders, multi-market analysis of fall Arbitrons shows," pp. R-2—R-32. Leading stations were defined by *Television/Radio Age* to include the top 10 stations in the top 10 markets and the top five stations in the remaining 71 measured markets.

[125A] "FM: The great leaps forward," pp. 32–49.

[126] FCC, "AM and FM Broadcast Financial Data, 1977," December 11, 1978.

69. The *Broadcasting* article of January 22, 1979 provides strong evidence that just such dynamic competitive forces are at work in large radio markets. The most obvious recent example is the dramatic growth in audience for those stations that switched to disco formats. Thus, for example, when WKTU(FM) in New York switched from soft-rock to disco, its share rose from 1.4 in the July–August Arbitron book to 11.3 in the October–November Arbitron book.[127]

70. In conclusion, the evidence cited above shows that the dramatic growth in the number of radio stations, particularly FM, has not simply represented an increase in the number of fringe or marginal stations in urban areas, but rather has increased the number of strong, viable competitors in these markets. This kind of competition tends to force stations, in their own self interest, to be responsive to shifts in consumer tastes or else lose their audience to more responsive stations.

Changed role of radio among informational media

71. Concurrent with the increased competition in urban radio markets, television has developed as a competing entertainment and informational medium that adds a visual dimension to the aural dimension offered by radio. The public prefers certain services, such as dramatizations and on-the-spot news and sports coverage, to have both audio and visual dimensions. Thus, it is not surprising that television has to varying degrees replaced radio in the provision of these services. For example, Roper polls show that television has now become *the* primary source of news and information about our society and current problems.[128] In responding to a question about where they get most of their news, 67% of those interviewed identified television, whereas 49% identified newspapers as a primary news source, and only 20% identified radio.[129] According to a 1977 survey of "key decision makers in politics, business and professions" by *U.S. News and World Report*, only the White House ranked above television in "the amount of influence it has on decisions affecting the nation as a whole." [130]

72. Existing technology, however, also places some restrictions on the role of television. Even in large markets, the number of television assignments allowed by current rules is far less than the number of radio stations in those same markets. As a result, over-the-air television transmission is limited. Also, television has substantially greater fixed production costs than does radio, and therefore television operators have a larger tendency than do radio operators to seek broad, "common-denominator" programming (both entertainment and informational) in order to spread these costs over large audiences. Because of the resulting economics of television, it does not lend itself to providing programming for specialty tastes as easily as radio.[131]

73. There has proved to be considerable demand for "mass audience" programming and also for commercial time, and therefore television has been a great economic success. Large national audiences have attracted national advertisers. There is a substantial amount of local and national advertising on television, but demand for television commercial time is growing faster than the available supply of commercial time due to the small number of stations. Therefore, the cost to advertisers of television time is increasing, and for many small and/or local advertisers television, quite simply, may not be a cost effective medium. In particular, as long as economic factors dictate that television programming must cater to general audiences, television may not be the medium of choice for advertisers seeking narrowly defined target audiences. Hence small, local, and specialty advertisers often may seek alternate advertising media. Both because of lower costs and more localized or specialized audiences, radio is one of those media. This, in turn, suggests that individual radio stations may prosper by selecting an audience that is either not served at all by existing stations or not completely satisfied with existing stations.

Specialization in radio

74. A fairly large body of data shows that radio has become increasingly specialized as a medium. Unlike television, radio stations specialized in entertainment (or informational) formats, choosing one to the total exclusion of others.[132] Additionally, however, radio stations also specialize by the segment of the population they try to serve. Such specialization can be seen in the data collected by the Standard Rate and Data Service, Inc. (SRDS). SRDS includes in its monthly "Spot Radio Rates and Data" book, which is used by advertisers and advertising agencies, information on Black and Spanish population by locality, and the number of hours of regularly scheduled Black and Spanish (and other foreign language) programming by station. Tables 4 through 7 summarize the SRDS data on monority programming.

75. Table 4 indicates that 416 radio stations in 239 markets provide some regularly scheduled Black-oriented programming.[133] One hundred and thirty-nine of these stations provide full-time Black-oriented programming. In 83 markets there are two or more stations providing regularly scheduled Black-oriented programming; in 11 markets there are 5 or more stations. In one market, Atlanta, there are 9 stations providing some regularly scheduled Black-oriented programming.

76. Table 5 shows that there is at least one station with full time Black-oriented programming in 11 of the 12 markets with more than 31 stations; 14 of the 19 markets with 23 to 31 stations; 15 of the 31 markets with 16 to 22 stations; 20 of the 74 markets with 10 to 16 stations, and 7 of the 36 markets with 8 to 10 stations. There are also 46 markets with 8 or more stations that have some regularly scheduled Black-oriented programming. Many of the markets without any regularly scheduled Black-oriented programming are in the Northwest or Rocky Mountain regions or other areas with very small Black populations.

77. Table 6 indicates that 270 stations in 173 markets provide some regularly scheduled Spanish language programming. Forty-four stations provide full time Spanish language programming.[134] In 55 markets, 2 or more stations provide some regularly scheduled Spanish language programming; in 7 markets 5 or more stations provide Spanish language programming.

[127] *Broadcasting*, January 22, 1979, p. 32.

[128] *Changing Public Attitudes Toward Television and Other Mass Media, 1959–1978: A Report by the Roper Organization, Inc.* (Television Information, 1979), pp. 2–3.

[129] In this Roper poll, respondents were able to list more than one primary news source.

[130] Quoted in Marvin Barrett, *Rich News, Poor News* (New York: Thomas Crowell Company, 1978), p. 7.

[131] Radio programming in small markets may tend to be less specialized than in large markets, but more specialized than television. Radio does not have to contend with the large fixed costs facing television, and therefore there exists less pressure to seek general audiences. The limited size of the potential audience and the relatively homogeneous population found in small markets, however, will tend to limit the amount of specialization.

[132] While there is a fairly high degree of imprecision in defining format types, *Broadcasting Yearbook*, 1979, lists over twenty major radio format types.

[133] SRDS leaves it to the discretion of the individual station to determine what constitutes Black-oriented programming.

[134] This may slightly overstate the total, as several very powerful stations that cover both the Los Angeles and San Diego markets were counted in each market.

78. Table 7 shows the very wide diversity of other regularly scheduled foreign language and ethnic programming. Programming exists in 63 foreign languages or dialects.

79. The SRDS data used in Tables 4 through 7 provides a very conservative estimate of foreign language, ethnic, and Black-oriented programming. SRDS data are updated monthly on the basis of data collection forms sent out to all stations. Only those stations that return completed forms and pay a fee to be listed are included in the Black-oriented and foreign language programming listings. A comparison with similar, but less detailed, data presented in *Broadcasting Yearbook* in its Format and Special Programming sections (summarized in Table 8) suggests that a considerable amount of foreign language and Black-oriented programming goes unreported by SRDS.[135] We have chosen to rely upon the more conservative SRDS estimates in order to be sure that we do not overstate any evidence in support of the hypothesis that radio markets will respond to foreign language, ethnic, or Black-oriented programming demands on their own.

Increased social diversity and the changing nature of community

80. The technological developments in broadcasting and the increasing specialization of radio have occurred during a period of considerable social and political change. The old melting-pot theory of American society has been challenged in the 1960's and 1970's by a growing awareness of our diversity. Increased emphasis has been placed on ethnic, racial, and sexual identities. Geographic localities may have heterogeneous populations. We are now more sensitive to the fact that urban areas contain several smaller communities defined less by geographic proximity than by other common factors. Ethnically, racially, and sexually defined communities have begun to develop their own social institutions—such as community centers, health clinics, and literature—and are also using their identities to develop political and economic strength. The evolution of new academic disciplines such as Black and women's studies also reflects this new awareness.

81. The growing awareness of diversity includes awareness that communities of common interests need not have geographic bounds. For example, Blacks in Chicago might identify more closely with and have tastes and needs more akin to other Blacks in Philadelphia than to Ukranians in Chicago.

82. Traditional institutions have responded in various ways to the new concept of community and the forces behind it. Some cannot adapt quickly to changes as others can. For example, television, structurally dependent on large, heterogeneous audiences, may have greater difficulty than radio responding efficiently to the specific interests of particular ethnic, racial, or sexual groups. Television licensees have little economic incentive to adapt.

83. The economics of radio, however, allowed that medium to be far more sensitive to the diversity within a community and the attendant specialized community needs. Increased competition in large urban markets has forced stations to choose programming strategies very carefully. Some stations seem to have taken a traditional approach, seeking to attract wide audiences and general advertisers with middle-of-the-road programming.

84. The fragmentation of markets among many competing stations, however, has apparently made an alternative strategy—specialized programming to attract a narrow audience of interest to specialized advertisers—increasingly attractive. As the number of signals increases, the expected size of the audience for any one station falls. In turn, this means that the expected gains from seeking a homogeneous audience through specialized programming rise relative to the expected gains from seeking a diverse audience through middle of the road programming.

85. Although advertisers generally prefer larger audiences, they also recongnize the benefits of seeking a homogeneous audience. As the expected audience size falls, the advantages of having a specialized audience increase. Radio has become increasingly profitable while this trend toward specialization has developed. This would suggest that both audiences and advertisers are pleased with the results.

Specialization in informational programming

86. The trend toward specialized formats has also had an impact on informational programming. As radio stations cater to narrow, well-defined audiences rather than broad audiences, it becomes economically feasible for them to expend resources on special news and public service programming that is of interest to its specialized audience, but would not be of interest to a broader audience. The growth of Black-oriented stations in many radio markets has created sufficient demand to support two different Black news and information networks in the U.S. today, the National Black Network and the mutual Black Network. Each network has between 80 and 90 affiliates and offers a five-minute newscast hourly, two to three sportcasts daily, and various public affairs programs during the week.[136]

87. Similarly, Spanish language formats generally include Spanish language informational programming. There is one Spanish language information network, the Spanish Information Service Network, a subsidiary of the Texas Informational Network. The Spanish Information Service has 22 affiliates in Texas, and broadcasts hourly news, twice-a-day "sportscasts," and a weekly 15-minute public affairs program.

88. In addition to the development of specialty news networks, the trend toward specialized radio formats has spawned a large number of all-news or news-and-informational radio stations. For example, *Broadcasting Yearbook* for 1979 lists 118 all-news stations.[137]

89. It should be noted that the networks operating today bear no resemblance to the radio networks of the 1920's that helped precipitate the initial government intervention into radio markets. Those early networks owned or controlled most radio stations and provided the bulk of the programming. As noted above,[137A] structurally radio in the 1920's was tending toward a concentration of voices. Today's networks primarily provide specialized programming for only a portion of the day. The result has been to increase diversity rather than uniformity.

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[135] For example, the 1979 *Broadcasting Yearbook* reports 793 stations providing Black-oriented programming vs. the 416 stations according to SRDS. As a particular example, *Broadcasting Yearbook* lists KYYX (FM) and KHNC (FM) Seattle as providing Black programming, but SRDS does not list either station. Hence our Tables 4 and 5 do not include Seattle as a market with some Black-oriented programming.

[136] The National Black Network offers five minutes of news every hour on the hour for 18 hours daily, seven days a week, and two five minute sportscasts daily, six days a week. In addition, the network offers several news/public affairs programs weekly, such as "Black Issues in the Black Press" (30-minute news commentary), "Action Woman Show" (30 minutes on the contributions of outstanding women to Black America), and "One Black Man's Opinion" (five 2½ minute editorials on the news).

The Mutual Black Network, a subsidiary of the Mutual Broadcasting System, offers five minutes of news ten minutes before the hour 16 times daily, seven days a week and three five-minute sportscasts daily. It also offers daily public affairs programming. This includes "Commentary in Black" (10-minute daily editorial on the news), "Message" (2 minute, 20 second weekday comment on a public issue), and a forthcoming "Dear Dr. Mitchell" (3 minutes, 30 second daily health program).

[137] This will be discussed in greater detail in paragraph 176, *et seq., infra*.

[137A] *See* paragraphs 8 and 9, *supra*.

Noncommercial radio

90. A final structural change that deserves notice is the growth of noncommercial radio. Table 3 indicates that virtually all urban markets have one or more such stations. These stations generally provide more nonentertainment programming than do commercial stations. We shall look in greater detail at the nonentertainment programming provided by noncommercial stations that are affiliated with National Public Radio below.[137B]

91. In sum, there have been three major, ongoing structural changes in radio: (1) Competition has increased substantially, especially in the larger markets, with many markets enjoying the benefits of a large number of viable, competing stations; (2) radio's role among the various media has shifted from being the major mass medium to being more of a secondary and often specialized medium; and (3) the concept of community has changed in recognition of the diversity of American society, and radio has been responsive to this change.

C. The Economic Policy Model

92. The structural changes outlined above have prompted this re-evaluation of Commission rules and policies. It is necessary to perform such a re-evaluation within an analytical framework that appropriately takes into account the Commission's public interest objectives. Consumer well-being is the major yardstick of this framework.[138]

93. There are two fundamental criteria of good performance in a market: (1) The goods or services supplied should closely correspond to the goods and services that the public wants; and (2) these goods and services should be provided at the lowest possible cost (consistent with the producers being able to remain in business over the long term).

94. The American public is very diverse and so are its wants. Each individual has his own set of tastes and preferences. Not only are many different goods and services desired, but in addition there is a considerable diversity in the *intensity* with which people want these various products. Some consumers value a particular product more highly than others and as a consequence are willing to pay more for the item. If there is no price tag on the item, there is no way to take into account the intensity of demand felt by individual consumers.

95. When consumer wants are diverse, they are difficult to measure. Government regulators lack the wherewithal to gather the information necessary to ascertain consumer preferences accurately. At best, centralized regulators can construct an aggregate picture that reflects overall tastes but probably fails to recognize local differences. Competitive markets, on the other hand, are particularly effective at determining varied wants (both of kind and of intensity). Consumers with the most intense demand for a scarce commodity will outbid those with less desire for the good.

96. For any given item, say apples, there is a group of consumers who will value apples, but the degree to which they value apples differs.[139] At a low price for apples compared to other items, many consumers will buy apples. If the price rises relative to the prices of other items, fewer and fewer consumers will continue to buy apples. The consumers who cease buying apples will be those who value apples less than the price. Thus, the pricing mechanism will ensure that the consumers who value apples most get them when they are scarce. Moreover, if there are no barriers preventing persons from becoming apple producers and if apple producers are able to earn profits equivalent to the return from other activities, they will serve the consumers with intense demand even if those consumers are very few in number.

97. Producers (providers) of goods and services must be responsive to consumers' desires in order to compete successfully with rival producers.[140] Consumers, by their choice of purchases, determine which producers (providers) will succeed. Moreover, not only does the competition among producers for consumers lead to the production of the goods and services that consumers want most, the same competitive process forces producers continually to seek less costly ways of providing those goods and services. As a result, parties operating freely in a competitive market environment will determine and fulfill consumer wants, and do so efficiently. That is, for any given distribution of income and wealth among consumers, competitive markets will produce at lowest cost those goods and services that consumers value the most. Therefore, in the absence of strong countervailing reasons, it is good public policy to encourage competition, to pursue policies that ease entry and increase the number of competitors, and wherever possible to allow market forces to operate freely.

Market failure in general

98. There are situations, however, in which markets may fail, that is, in which a market may not respond fully to consumer wants. In particular, markets may not satisfy consumer preferences at least cost if: (1) They have noncompetitive structures; (2) the good or service, once produced, can be made available to additional consumers without cost (labeled by economists a "public good"); or (3) there are relevent social costs or benefits from the market activity that the market does not take into account. In these situations, regulatory intervention in the market may be warranted, if the benefits from that intervention outweigh the costs.

a. Noncompetive markets

99. Noncompetitive markets, with few producers, and with barriers that prevent other possible producers from coming in to challenge the existing producers, are less likely to be responsive to consumer preferences than competitive markets Comsumers will have fewer alternate sources of supply to turn to if their wants are not met, and therefore suppliers can set prices above costs of production. Furthermore, since the consequences of failing to produce at lowest cost are not as drastic as for competitive firms, the few producers will be likely to waste resources using less efficient production techniques.

Public goods

100. "Public goods" are those that, once produced, can be made available to additional consumers without having to use any additional resources and without diminishing the supply availabe to the intial consumers.[141] It can be said that the consumers of public goods are "jointly supplied." An example of a public good is national defense. Once a given expenditure has been made for national defense, the protection accorded covers all. New citizens receive the benefits of protection without diminishing the quantity accorded to other citizens.

101. Public goods are also unique in that additional consumers either cannot be excluded from enjoying the good or service, or can be excluded only at

[137B] *See* paragraphs 157 and 158, *infra*.

[138] *See* paragraph 52, *supra*.

[139] There will be some consumers who will not acquire apples even if they are given away, but this group is likely to be quite small.

[140] If other firms could fairly easily become producers, they serve almost the same competitive spur as actual rival producers in a market.

[141] The classic reference in the modern literature is P.A. Samuelson, "The Pure Theory of Public Expenditure," *Review of Economics and Statistics* 36 (November 1954), 387–89.

prohibitive expense to the initial consumers.

102. Many goods are not "pure" public goods but to some extent can be jointly supplied to consumers. In other cases, it may be very difficult to exclude consumers from enjoying the good or service. For example, a large public park can be enjoyed by many consumers, although a group on a picnic may find the noise from a nearby volleyball game slightly bothersome—this alters the "joint supply" feature mildly. The park could be privately owned and operated by an entrepreneur who was able to erect a fence and charge a fee to recover operating and maintenance fees. Although the benefits could be restricted to those willing to pay the entry fee, society may be unwilling to abide by that sort of exclusion. This is an example of what economists call a "quasi-public good."

103. Markets implicitly ask consumers how much they are willing to pay for a good or service. If a consumer is unwilling to pay the price necessary to induce suppliers to provide the item, he will not get the good. For a public good, however, the consumption of that good or service does not reduce its availability to others and, therefore, if an individual consumer can induce others to pay for the initial production of the good, he can enjoy it for free. In effect, he gets a "free ride." If the rational consumer were asked how much he would be willing to pay for a public good, he would say zero and still enjoy the good if others were willing to pay the costs of producing the item. The rub is that there must be enough people willing to cover the (fixed) costs of production, in order to get the good produced initially.

104. Even if it were possible to make all consumers contribute to the cost of a quasi-public good, because adding more consumers does not add to the cost of making that good available, making all users contribute equally results in fewer users than could be allowed. For example, a large museum could be maintained profitably by a private owner charging admission fees to cover the operating and acquisition costs. But this will deny admission to consumers interested in the collection who would be willing to pay the costs of wear and tear they impose on the museum but not the full admittance fee that also covers the costs of the exhibits.[142]

105. The private market for this quasi-public good therefore denies the good to some consumers, even though they could "consume" it without diminishing its availability to other consumers or requiring additional resource expenditure.

c. Social benefits or costs not accounted for by the market

106. The third set of circumstances that can lead to market performance inconsistent with the public well-being involves cases where the producers and consumers of a good or service are not the only parties affected by the production or consumption of that item.

107. For most goods and services in our economy, the costs of producing a particular good or service and the benefits from consuming that item are easy to identify, and are received by the persons who produce or buy the item. The costs are the total value of the scarce resources (materials, labor, capital) used to produce the item. These are costs to society because these resources otherwise could have been used to produce other goods or services. The benefits derived are the value of the well-being that the consumer attains from purchaasing (consuming) the item. The producer of the item takes into account his costs and the consumer his benefits when their decisions are made to supply or purchase the item at a particular price. The market mechanism incorporates all this information and a price is set equal to the cost of producing an additionl unit of the good.

108. There may exist situations, however, in which others besides the producer or consumer of an item directly benefit or suffer from the production or consumption of an item. For example, if the use of an automobile creates air pollution, then others who breathe the polluted air will suffer. The total costs to society of using that automobile are greater than the simple sum of the costs of producing the car and the gasoline it burns.

109. Because the market prices of the automobile and the gasoline do not take into account the costs to society of correcting for the pollution, those pollution costs remain "external" to the market and the market price does not include all the social costs of operating the automobile. If the pollution costs were "internalized" into the market, then the price of operating automobiles would increase, and the number in use would fall. When the market mechanism does not take into account the "external" costs, more automobiles are used than is optimal. The failure to take into account such "externalities" therefore results in market solutions that are not socially optimal.

Government response to market failures

110. In each of these circumstances—noncompetitive market structure, provision of public or quasi-public goods, or the existence of externalities—market failure may warrant corrective government action. Noncompetitive market structures might be indirectly policed (e.g., antitrust surveillance), or certain market activities might be prohibited. In the extreme (e.g., a natural monopoly such as electric power transmission or a subway) the government may own or regulate production of this good. In the case of externalities, direct regulation (e.g., mandatory pollution control devices) or compensatory taxes or subsidies (e.g., tax credits for energy conserving devices) may be implemented.

111. Each of these forms of government actions, however, has costs associated with it—the direct cost of government enforcement, the costs imposed on the regulated parties,[143] and the indirect costs imposed on consumers if regulators fail to gauge accurately (or decide to override) consumer wants. Ultimately these costs fall upon the public both as taxpayers and as consumers. It is therefore appropriate to compare these costs to the benefits of government action before undertaking such action. Government intervention should be considered only on a case-by-case basis.

112. Government remedies for the provision of public and quasi-public goods have varied, but have generally involved either direct supply of public goods by the government (e.g., national defense, police protection, fireworks displays, dams), or intervention in private markets for quasi-public goods (grants to museums and research foundations). The difficulty lies in determining whether or not a public good should be produced, and if so how much. "How much" national defense is optimal? Presumably it is appropriate to keep on expending resources as long as the additional benefits from the increased production exceed the additional costs. The "additional benefit" is merely the sum of all consumers' demand (or willingness to pay) for the public good. More intense demand by consumers for a public good increases the socially optimal level of its production.[144]

113. The actual social accounting of consumer preferences is never carried

[142] We are assuming, of course, that the museum will remain uncrowed.

[143] Some of these costs may include efforts by the regulated parties to thwart, bend, or otherwise evade the government action.

[144] For example, other things being equal, the optimal level of national defense woud be higher for a "hawkish" than a "dovish" population.

out in practice, since consumers would have the incentive to mask their preferences for the public good, in order to exploit the "free ride" when others come forward and pay the costs. Instead, the government must rely on the political process in which citizens vote for candidates whose preferences agree as nearly as possible with their own preferences about which public goods should be produced. Voters implicitly compare the benefits from the public goods to their expected share of the tax burden necessary to produce those goods.

114. Clearly government provision of public goods is subject to at least as many pitfalls as other forms of intervention in the market, and the decision to supplant the private market for quasi-public goods (e.g., education, libraries, public health) has had massive consequences for the economy.

Other reasons for government intervention

115. There are certain social, political, and moral goals in a society that are largely independent of market considerations. Thus, when markets respond efficiently to consumer wants, some persons may nonetheless judge that those wants are "undesirable" and should not be satisfied. As an example of "undesirable wants," consider that there is a strong demand by some consumers for pornographic literature, and surely a market exists for such products. Others, however, have deemed those wants undesirable and have successfully sought various restrictions on the distribution of this literature. One should note that this example represents a moral judgment that markets do not address. It is not a situation of market failure, but of a noneconomic social decision.

116. Further, some consumers, though they have strong wants, have insufficient income and wealth to register their wants in the marketplace. Society may decide, however, that those people's basic needs should be satisfied. The usual means of providing for those with insufficient income and wealth has been the various income redistribution programs of the government that enable the poor to register at least their basic needs for food, clothing and shelter in the marketplace.

Policy consequence of the economic model

117. Because it is always costly, government intervention to correct market failure should occur only to attain otherwise unattainable public interest objectives. It is therefore necessary for the government agency involved to articulate the public interest objectives that underlie any particular law, rule, or policy. Since government intervention has costs associated with it, it is appropriate to show why, absent that government action, the marketplace is unlikely to attain a public interest objective. A distinction should be made between potential market failure to attain the objective and actual or proven market failure. Policy decisions based on the former can be risky, in that once government intervention occurs it is impossible to show conclusively how the market would have operated absent the intervention. Therefore it is impossible to compare unambiguously the regulated result to a market result.

118. It is also appropriate to determine how far the market would stray from the public interest objective. If the market would fall just short of the goal, then the benefits from government intervention may be minimal while being costly. In that case the market may offer the better alternative. If, however, the market will be far short of the goal, then government intervention will likely be preferable. In short, both the costs and the benefits of government intervention should be considered.

119. In addition, there sometimes exist situations in which government action directed at one public interest objective may have an adverse effect on other objectives. In these instances, the positive and negative consequences must be weighed, and some balance struck among the various public interest objectives before any government action is undertaken.

120. Finally, it should be noted that government intervention generally occurs in response to market conditions at a point in time. However, market conditions often change rapidly. So do public interest objectives. Government regulations and other governmental activities should therefore be reviewed periodically to check their current relevance.

Applying the economic policy model to radio markets

a. The scarcity theory

121. Before analyzing the various unique features of radio markets, it is appropriate to consider the key assumption about market structure that has become the basis for most Commission regulatory activity—the "scarcity" theory. This theory was first developed in the 1920's when broadcasting was in its infancy and suffering from poor spectrum management and from monopolistic control of most radio outlets. Analysts in that period blamed the monopolization on an inherent technological scarcity that would of necessity yield a monopolistic or oligopolistic structure that could not respond to public needs. In order to reduce technological interference to acceptable levels, it was assumed that the number of radio stations would have to be limited. In return for this monopoly position licensees, rather than being subject to traditional rate of return regulation like public utilities, would be required to provide certain unprofitable programming services that were construed to be in the public interest.

122. Developments since the 1920's render the scarcity theory overly simplified. In turn, the policies that have followed from it suffer both from the oversimplification and from a number of highly questionable assumptions. As will be shown below, some of the supposedly unprofitable programming services that were to be part of the *quid pro quo* for use of a limited resource are indeed profitable and would be supplied by licensees anyway. Of greater concern, some of the required programming is not favored by the listening public and therefore its provision may reduce consumer well-being. Given this, the question then becomes whether the benefits of such programming exceed the cost of regulations requiring it.

123. More fundamentally, the concept of scarcity is more complex than the simple scarcity theory suggests. Any good or service is scarce if, when offered at zero price, the total amount people would take exceeds the total amount available. As can be seen, virtually all goods and services in the economy are scarce. For each scarce good or service, some method must be devised to determine its allocation among would-be consumers.[145] Typically allocation takes place according to some pricing mechanism (i.e., people bid for scarce goods or services in terms of how much they are willing to pay for the items), or by government fiat (e.g., quotas or other rationing devices are imposed), or by some combination of the two (e.g., rationing tickets are provided but can be bought and sold).

124. The misconception of scarcity of radio spectrum arose in part from confusion between two aspects of spectrum use that interact to determine the total number of stations possible. One is the problem of interference

[145] Some things, such as air, are important because they are needed for survival, but they are not scarce. There is enough available for all to enjoy at zero price. It need not be allocated. This may not always be the case. Consider how drinkable water always has been scarce in some places.

among radio users. The second is the total quantity of spectrum allocated to radio.

125. Government intervention is needed to prevent interference among radio users. To do this the government has to determine such factors as the amount of frequency per channel, allowable power limits, and geographic spacing of stations. These do not necessarily remain constant over time, and the Commission has revisited these issues periodically.[146] Changes in these parameters change the total number of stations that can be allowed in any one geographic area even when the total amount of spectrum allocated to the broadcast radio service is constant.[147]

126. Radio spectrum has also been seen as scarce because additional spectrum space can be made available only with difficulty and at some expense. Radio listeners would have to purchase new receivers to take advantage of the new spectrum, and previous users of these frequencies would have to move to other parts of the spectrum. Hence adherents of the scarcity theory talk of technological scarcity. Such analysis, however, only looks at the supply of radio frequencies, not the demand for them. Currently, in many small radio markets not all allocations are taken.[147A] Radio frequencies are applied for only when the would-be broadcaster thinks he can make a profit selling advertising time and supplying programming. Goods and services will not be produced, even if such production is technologically possible unless there is sufficient demand to cover the costs (including a return to capital investment) of supplying the item. Thus, in many small markets, despite the fixed amount of radio spectrum available, there is no scarcity of spectrum space. The problem is limited demand for advertising that in turn limits the amount of programming that can be provided.

127. In the long run, economic scarcity tends to induce changes in the amount of spectrum available for radio. It is possible to increase the number of radio outlets by increasing the amount of spectrum space allocated to radio.[148] The number of outlets can also be increased by changing how the radio spectrum is managed. By installing improved equipment the parameters such as frequency per channel, power limits, and geographic spacing may be able to be reduced without increasing interference.[149]

128. The willingness to adopt technological advances that will increase the number of stations depends on economic considerations. At some point after demand exceeds supply, the costs associated with technological changes like those listed above may become smaller than the benefits from the increased number of radio stations. In this regard, radio is analogous to other goods and services that, at least in the reasonably short run, are fixed in supply. Consider land or mineral ores. Over time, as demand increases, more and more previously unusable land is made usable through various technological advances. To take the most extreme case, Holland reclaimed the sea: drained large areas, removed the salt, and made it usable for farming. Similarly, as the demand for metallic ores increases and supply falls, new techniques are developed for recovering lesser grades of ore.

129. The limits on spectrum use, as on other goods, have been primarily economic rather than imposed by some immutable technology. It is appropriate, therefore, that broadcast radio be treated the same way as land, mineral ore—or newspapers—and that regulation be limited to the kinds of situations previously set out in which the market is perceived to work imperfectly.

b. Radio as a quasi-public good

130. Radio markets possesss both the major characteristics of public goods, nonexcludability and joint supply. Broadcast signals can be received by anyone possessing a receiver without payment to the signal originator. Only by use of a complex and expensive scrambling and revenue collection system could radio broadcasters charge directly for their programs, and that system would probably not be viable since the benefits from the programming might not be as great as the costs of the system. Joint supply, or the failure of consumption by one person to detract from availability to others, is also clearly a feature of radio broadcasting.

131. The expected failure of a private radio broadcasting market, as predicted by the theory of public goods, would seem to dictate direct government provision of the service. As with national defense, it would appear optimal for the government to supply the radio broadcasts that satisfy the perceived collective wants of society. This would require the government to estimate and weigh consumer preferences, both between specific program types and between radio and other commodities.

132. The willingness of advertisers to support programming in order to sell their messages, however, presents the government with the alternative of relying primarily on private enterprise to supply this public good. Congress and this Commission have enthusiastically endorsed this alternative (particularly with the addition of public broadcasting to supplement commercial broadcasting) as it is consistent with the First Amendment provisions on Free Speech and decentralizes access and control over information and ideas in society.[150] Moreover, private broadcasting to a great degree can allow consumers considerable choice over programming (to the extent advertisers must attract listeners), and eliminates the basic inefficiencies inherent in direct government ownerhsip or control over an industry.[151]

133. The question that naturally arises in this reevaluation of our regulation of radio broadcast markets is to what extent does the advertiser supported medium satisfy listener demand. Our review of structural changes in radio markets, as well as the ensuing discussion of behavior in the industry, leads us to believe that consumers have

[146] See, for example: *Further Notice of Proposed Rule Making in the matter of Clear Channel Broadcasting in the AM Broadcast Band,* Docket 20642, 70 F.C.C. 2d 1077 (1979); *Notice of Inquiry in the matter of 9 kHz Channel Spacings for AM Broadcasting,* adopted June 17, 1979.

[147] It should be noted that the total amount of spectrum allocated to the radio broadcast spectrum has changed. In 1940, the FM band was established. Currently, the United States position at the 1979 World Administrative Radio Conference includes a proposal that the AM band be expanded, permitting hundreds of additional outlets.

[147A] As of June 5, 1979, there were 386 vacant FM assignments for which no applications were pending. The FM Table of Assignments was not designed to totally saturate the spectrum, but rather was designed to allow for the possibility of dropping-in a limited number of additional stations in the future in response to growth over time. Additional FM stations are therefore technologically, if not economically, feasible. There is no table of assignments for AM radio but it would be technologically possible to drop-in a limited number of additional stations.

[148] *See* note 147, *supra.*

[149] *See* note 146, *supra.*

[150] Despite public funding for public broadcasting, great efforts are being made to prevent governmental involvement in programming decisions in deference to the First Amendment.

[151] *A public Trust: The Report of the Carnegie Commission on the Future of Public Broadcasting.* (New York: Bantam Books, 1979), pp. 93–148. Government ownership of industry results in many of the same problems as does monopolization: Lack of competition means laxity in the use of resources, and slows the adoption of technological innovations. The ability (and frequent willingness) of the government to subsidize government-owned industries may hold down prices that consumers pay for a while, but the slow adoption of technological improvements ultimately requires either growing subsidies or higher prices. For a more lengthy discussion of the inefficiencies, see Charles Wolf, Jr., "A Theory of Nonmarket Failure Framework for Implementation Analysis," *Journal of Law and Economics,* vol. xxii, No. 1, April 1979, p. 107–139.

a great deal of control over radio programming. Competition among stations makes them very attentive to consumer demand in order to increase their audience share. These forces place a natural limit on the proportion of time devoted to advertising as well as inducing stations to broadcast certain types of programming. To that extent we can remove many regulatory constraints and devote government resources to supplementing private broadcasting by continued support to noncommercial radio.

Behavior of the advertiser supported industry

134. Advertisers are interested in selling their products. To the extent that fulfilling consumers' broadcasting wants is consistent with that goal, they will fulfill consumer wants. There is considerable overlap of interest. Advertisers do seek large audiences and therefore will provide programming that is broadly popular. Advertisers, however, primarily seek to reach those particular audiences most likely to purchase their products. Therefore, advertisers may be more responsive to the broadcast wants of certain groups—the more affluent and the young adult, for example. Others may be less well served.

135. An alternate way to view radio markets is to consider the audience the product, and the advertiser the purchaser. That is, the advertiser is purchasing eardrums. Programming is the medium used to attract these eardrums. In general, the more eardrums attracted for a given amount of money, the better off the advertiser. Not all eardrums are equally valued by the advertiser, however. The most highly valued eardrums are those of individuals who will buy his advertised product. Higher income and young adult eardrums may be generally preferred by advertisers and therefore may become the target of advertisers. Programming would then be addressed to these groups. The more specialized the product being advertised, the more specialized the programming will be.

136. Although certain audiences may be preferred to others, it may well be that some of the nonfavored audiences (for example, low income groups) will fare as well or better in a commercially sponsored radio market than in a traditional direct payment market. While advertisers may not particularly seek low income audiences, it is also true that in traditional markets individuals with low incomes will have fewer dollars to "vote" with in making their consumer choices.[151A] Hence, these individuals may not be harmed by advertisers' preferences.[152] Certain demographic groups, however, particularly the elderly, may not be valued highly by advertisers and thereby may have less impact on programming than they would under a traditional market arrangement.

137. Of even greater concern, however, is the fact that, by providing programming at a zero price, the market is unable to measure the intensity of demand for particular programming. The market chooses programming that will attract the targeted audiences at zero price. Under the present system, there is no way to distinguish between programming that consumers would be willing to pay for, if necessary, and that which consumers would take for free, but not pay for. Clearly, consumers are better off if they receive programs with a high value rather than ones with a low or zero value to them.

138. It is difficult to determine the consequences of zero prices on policy making. For example, it is sometimes argued that minority tastes are not met by the broadcast media because zero pricing recognizes market size, but not intensity of demand. Without considerable information on individual consumers' demand (which is expensive to collect) it is impossible to measure demand intensity. How would one determine whether the intensity of demand for the first sports talk program was greater than that for the third rock program? It has been suggested that listener complaints—especially if organized—are a measure of demand intensity. Unfortunately, such complaints may represent only one segment of the population (and likely the better educated one) and therefore may not be representative of overall consumer wants.

139. It seems likely, however, that the more stations there are providing programming, the more likely minority tastes will be served adequately. As the number of stations in a market increases, the expected market share (and the expected audience size) of each station will fall. With smaller expected audiences, it may become more attractive for individual stations to seek small, specialized audiences with strongly held, but not widely shared, tastes. Consider for example a market in which the number of stations doubled in a decade from five to ten. Suppose that throughout the decade in that market 10% of the population had a strong preference for a certain type of programming that nobody else liked, but that minority audience would listen to other programming if the preferred programming were unavailable. Initially, it would have been unlikely that any of the five stations would have catered to that minority audience, since expected market share with other programming would be 20%. But at the end of the decade when there were ten stations, there might well be a station that would provide that minority programming in order to gain a 10% audience share. In general, the more competitors there are in a radio market, the more responsive that market will be to strong, but limited, minority tastes.

140. A number of economists have tried to model more formally the workings of broadcast markets. As a result literature exists that addresses the issue of performance in these markets in terms of their ability to satisfy consumer wants (provide consumer well-being).[153] As is often the case, the models raise important new questions as well as answering old ones. In particular, these models very clearly demonstrate the vast body of information needed for a regulator to be able to intervene in the market with confidence that such intervention will be beneficial.

141. The earliest economic models of broadcast markets, in order to avoid difficult data collection problems, relied on simplistic (even heroic) assumptions that made the analysis manageable, but reduced the applicability of any policy implications. Thus, when Steiner made the first attempt to model radio markets, he assumed that each listener had one preferred program type and that if that program type were not available the listener would tune out entirely. The

[151A] In fact, there is considerable empirical evidence that low income individuals tend more than higher income individuals to buy brand name products and therefore advertisers are likely to try to appeal to that group which is most highly responsive to advertised products.

[152] This impression, however, does not take into account that such groups may have a high intensity of demand for certain types of programming. In other words, they might be willing to pay more than others and more than might be expected if the programming were provided by a direct pay system.

[153] For example, Steiner, Peter O., "Program Patterns and Preferences, and the Workability of Competition in Radio Broadcasting," *Quarterly Journal of Economics*, LXVI (May 1952), 194–223; Wiles, Peter, "Pilkington and the Theory of Value," *Economic Journal*, LXXIII (June 1963), 183–200; Rothenberg, Jerome, "Consumer Sovereignty and the Economics of TV Programming," *Studies in Public Communication*, IV (Fall 1962), 45–54; Spence, Michael and Bruce Owen, "Television Programming, Monopolistic Competition, and Welfare," *Quarterly Journal of Economics*, XCI (Feb. 1977), 103–126; Beebe, Jack H., "Institutional Structure and Program Choices in Television Markets," *Quarterly Journal of Economics*, XCI (Feb. 1977), 15–37. Although several of these models directly address policy issues relating to television, they are all sufficiently general to apply to radio broadcasting as well.

listener had no second choice that provided some, though less, satisfaction. Hence, any listener whose minority tastes were not met would receive no satisfaction whatsoever. Also, Steiner attached equal weight to each listener; no one listener had greater intensity of demand for radio than any other. In this simplified world, consumer well-being could be unambiguously measured by the size of the audience. A monopolist, or an omniscient regulator, need not know anything more than the program type preferred by each listener to be able to provide maximum consumer well-being. In fact, however, listeners seem to have an hierarchy of preferences, and therefore simple audience maximization will not result in maximum consumer well-being.

142. Economists were not satisfied with the analytical capabilities of the Steiner model and several constructed new models that allowed for greater variety and complexity of consumer tastes. As the literature evolved it showed an increasing awareness of the many factors that affect broadcast markets and an increasing comprehension of how, and how well, those markets, with or without regulatory intervention, will satisfy consumer wants. Among the important considerations that must be taken into account:

—Are different programs within particular program types indistinguishable to listeners? That is, do listeners perfer some programs within a program type over others so that the programs are not perfect substitutes for one another, or are they indifferent, suggesting all programming within a given program type is perfectly substitutable? If these programs are distinguishable, then the broadcast of additional programs of a given type can increase consumer well-being, it does not simply represent duplication or imitation. Now it becomes very difficult and requires considerable information to compare the satisfaction from a third rock program to that from the first sports talk show.

—Do listeners have a second choice program, third choice program, and so on, if their higher choice programs are not available?

—Do listeners have an hierarchy of choices? If so, what are its characteristics? For example, are most first choices highly specialized and therefore unlikely to be met by mass audience "common denominator" programming? Does common denominator programming represent lower choice programming for most people? Do the lower choice programs privide listeners almost as much satisfaction as their higher choices, or not nearly so much? Without this information it is impossible to evaluate how well individual markets are satisfying consumer wants.

—How skewed is the distribution of tastes among the listening population? For example, if there is a listening audience of 100 people, one would expect different programming (and consumer well-being demands different programming) if 80 people prefer rock, 15 beautiful music, and 5 all-news as opposed to 40 preferring rock, 32 beautiful music, and 28 all-news. The latter distribution of preferences would (and should, if all rock stations are not perfect substitutes) provide more program types.

—What technological constraints are there on the number of stations in the market?

—Are there differentials in the costs of producing different radio programs?

—What are the values of advertising revenues?[154]

Using either assumed values or actual empirical data for the variables outlined above, it is possible to analyze how well radio markets will satisfy consumer wants.

143. Recent papers by Beebe and by Spence and Owen have provided quite general frameworks free of the restrictive assumptions used by earlier modelers for analyzing radio markets under many alternate demand and cost conditions. These models provide considerable insight into advertiser-supported broadcast markets that can aid us in policymaking.

144. Beebe, Spence and Owen agree that advertiser-supported broadcast markets will not respond perfectly to consumer wants, primarily due to the failure to ascertain intensity of demand. Programming may not be offered even where there are no technological constraints on capacity and the marginal benefits of the programming would exceed the marginal costs. This is because total revenues for those programs would not cover total costs. Most likely to be omitted are (1) programming for which there is a small audience that highly values the programming (but cannot register that preference due to the lack of a pricing mechanism) and (2) high-cost programming.[155] There will be a tendency toward program duplication and imitation (if one defines provision of more than one program within a program type as representing duplication or imitation). Without specific information on relative demand intensities, however, it is impossible to judge whether the "duplicative" programming would provide less consumer well-being than the by-passed minority programming. It can only be stated that programming that provides less consumer satisfaction *might* be offered under the advertiser-supported system.

145. Beebe, Spence and Owen agree, however, that as the number of stations increases the radio market will cater increasingly to less well represented consumer tastes, so long as the demand for that programming is sufficient to cover its costs.[156] It can be stated unequivocally that an increase in the number of stations never leads to a decrease in program offerings or listener satisfaction.

146. One very important policy implication of the discussion above is how little an isolated piece of information tells us about a radio market. The fact that a market has no classical music programming but three beautiful music stations, for example, does not necessarily imply an imperfect market. To determine how well that market is functioning requires information on:

—How many people want classical music programming and how many want beautiful music as their first choice of programming?

—How strongly do each of these individuals want these first choices?

—Given the intensity with which the individuals want their first choice programming, how often would each individual *actually* listen if the format were available?

—What are their second choices?

—How strongly do they value their second choices?

—What are the relative costs of programming the two formats?

147. Without the answers to all these questions it is not possible to compare the consumer well-being from the "market" outcome (no classical music stations, three beautiful music stations), with the consumer well-being that would result if governmental intervention induced one or more stations to switch to classical music.

148. Such information will not be available to the Commission staff and is most unlikely to be provided in a Commission hearing room. Yet without such information it is impossible to predict whether or not any government action intended to influence programming in a marketplace will

[154] The last two considerations will affect the number of stations and type of programs that can be supported *economically* in a market. In the case of small markets especially, the constraint on the number of stations is likely to be economic not technological, *see* Note 158, *infra*.

[155] It is noteworthy that some of this type of programming, which predictably would be under supplied by the advertiser-supported market, is presently being provided by National Public radio stations and noncommercial listener-supported stations. This is perfectly consistent with the efficient satisfaction of consumer wants.

[156] It is impossible to generalize about how many stations are necessary for given amounts of minority programming to be provided. This will depend on the specific consumer preferences and cost conditions that exist in particular markets. The tendency toward provision of more minority programming as the number of stations increases, however, is unambiguous.

improve consumer well-being, even in an unambiguously imperfect market.[157]

149. It can be safely stated, however, that increasing the number of economically viable stations in a market will improve consumer well-being. This suggests that Commission involvement in radio markets ought to be limited, as much as possible, to easing entry into the industry.[158]

150. The structural and social changes discussed earlier are consistent with the predictions of the economic models of radio markets. A trend toward program specialization has followed the substantial increase in the number of radio stations. Data at such an aggregate level cannot be used to verify that individual markets are or are not providing optimal amounts of minority interest programming, but they do strongly support the generalization that increasing the number of competitors will improve the satisfaction of minority consumer wants.

Failure to provide sufficient informational programming

151. Perhaps the Commission's deepest concern during the last half century of broadcast regulation has been that the broadcast market might not provide sufficient informational programming (particularly news and public affairs programming).[159]

152. A well-informed citizenry is necessary for the smooth functioning of the democratic process. Not only does an individual citizen benefit from the information he has received from broadcast programming, but so do other citizens in the community. Thus, there are social benefits as well as private benefits from informational broadcasting.[160]

153. In a free market situation, when the radio station manager makes his decisions about what programming to air, he considers only those listeners who benefit directly from the programming. The commercial sponsor, and hence the station manager, probably has little interest in any secondary benefits accruing to other citizens from any informational programming. In entertainment programming, there will be fewer secondary social benefits to other citizens; the benefits accruing directly to the audience come closer to representing benefits to society.[161] Therefore, if decisions about programming are determined simply on the basis of the potential listeners without taking into account the social benefits of that programming to nonlisteners, too little informational programming might be provided.

154. The fact that there are benefits to society from informational programming however, does not automatically suggest, let alone prove, that market failure would occur if the market were allowed to operate freely. The unregulated market place might still provide a substantial amount of informational programming. Furthermore, even if there are benefits from informational programs that the market fails to take into account, and the market thus provides too few of those programs, it is important to determine how great the resultant market distortion would be.

155. It is possible, for example, that some or many citizens recognize the benefits to society at large of being well-informed and therefore listen to informational programming out of a sense of civic duty. Whatever the motives, however, the private demand for informational programming may be very close to the private plus social demand. In that case any market failure might prove to be minimal, and the amount of informational programming that the government should require might not differ much from the amount the market would produce. Requiring still more additional informational programming might make matters worse by forcing the use of radio resources to produce too much informational programming at the expense of more highly valued (by listeners) entertainment programming.[162]

156. The Government presently employs two principal nonmarket mechanisms to try to increase informational programming: (1) It sets aside a large share of the radio spectrum for noncommercial use, and partially subsidizes noncommercial station programming costs from the general treasury; and, (2) for all commercial radio stations, it suggests certain minimum quantitative programming guidelines for news and public affairs.[163] At present, no matter how many stations are operating in a particular radio market, and no matter what the aggregate level of informational programming in the market, the licensing process for each station depends in part on these minimum guidelines.[164]

157. Reserving valuable frequencies for noncommercial use is in effect a subsidy for the type of programming presented on those noncommercial stations.[165] That subsidy "in kind" is supplemented by the tax revenues provided for noncommercial programming. Noncommercial radio stations have varied purposes and formats, but many of them have strong inclinations toward informational programming. Currently 215 noncommercial stations belong to National Public Radio (NPR), which provides a heavy diet of regularly scheduled news and public affairs programming.

158. In fiscal year 1978, NPR provided 1,978.5 hours of informational

[157] There may be Commission actions aimed at public interest objectives unrelated to consumer choice. These are not considered here.

[158] The economics literature suggests that in small markets there may be less than optimal amounts of minority interest programming. This is due as much to economic conditions that exist in small markets for *all* goods and services, as to technological conditions unique to broadcasting. Consider, for example, restaurants, movie theatres, or furniture stores in small markets. In each of these cases only a small number of establishments can be economically supported by the small population, and they will tend to provide "common denominator" products. There will not be sufficient demand to support foreign restaurants, or art films, or Scandinavian modern furniture stores. Foregoing some of these special, minority consumer taste items is one cost of living in a small community. The same phenomenon holds in radio broadcasting. In fact, to the extent that listeners in small markets can receive distant signals they may be better served by radio than by markets for other goods and services.

[159] Public affairs programming may include in-depth interviews, political debates, and documentaries. See 47 CFR 73.1810(d)(1)(iv).

[160] This argument is analogous to one made in support of public education.

[161] Entertainment programming does in fact inform the public through its ability to create, reinforce, or weaken stereotypes, values, and other public perceptions. The resulting social benefits or costs are likely to be less direct, however, than those from informational programming about newsworthy topics of great immediacy. In any case, the Commission has always believed that First Amendment considerations preclude any direct regulation of program content. Although the Commission can encourage certain generic types of programming—for example, news or public affairs—it is not clear how the Commission could define what constitutes socially beneficial or nonbeneficial entertainment programming.

[162] Consider, for example, public affairs programming that is provided by a station at 3:00 a.m. The programming helps the licensee meet current Commission processing guidelines, but probably is aired at 3:00 a.m. precisely because few listeners are interested in the programming and the licensee prefers not to sacrifice more valuable air time. The social value of such programming is dubious given that so few will hear it.

[163] *See* 47 CFR 0.281(a)(8).

[164] There are other Commission rules and policies that less directly affect the quantity of informational programming. For example, the Commission's EEO, minority ownership, and ascertainment rules, although primarily concerned with the diversity of voices in radio, may indirectly encourage greater informational programming. These rules and policies will be addressed in the section on "Failure to Provide Many Voices" below. Also, in petition to deny or comparative renewal proceedings that are brought on grounds unrelated to informational programming, the Commission allows the licensee to introduce into the record evidence about its informational programming as an attenuating factor in some circumstances.

[165] Providing commercial frequencies without charge is also a subsidy for entertainment programming.

programming.[166] That represents 5.7 hours of informational programming daily. NPR's major informational programming vehicle, "All Things Considered," is provided for 90 minutes each weekday and 60 minutes each Saturday and Sunday. In fiscal 1978, NPR provided 488 program hours of "All Things Considered," 60 of which were news format, the remainder public affairs. In a survey of NPR members on program usage during the fourth quarter (July through September) of fiscal 1978, 158 of the 164 respondents (96%) indicated that they broadcast "All Things Considered" during midweek; 138 of the 164 (84%) on weekends.[167] The other regularly scheduled NPR news and public affairs programming was broadcast by between 40 and 91% of the respondents, typically by over 70%.

159. The subsidization of public radio by the government is a direct and fairly efficient means of assuring that certain types of programming are available. The cost to society as a whole of the subsidies to National Public Radio is the value of the alternative uses of the frequency spectrum space that are given up and the alternative uses of the programming subsidy money.

160. The second nonmarket mechanism for increasing informational programming—imposition of certain minimum quantitative programming guidelines for news and public affairs—represents direct intervention into the marketplace. Because some station managers will have profit incentives to provide entertainment programming that may be more profitable than informational programming, they may try to minimize the impact of the regulation on profits by scheduling informational programming during nonpeak hours or by not scheduling the required amount of such programming. As a result, scarce resources may be spent on programming that is hardly listened to while preferred format goes unbroadcast and unheard. If this situation occurs, the goals of informing citizens would not be met and listeners would not receive the programming they prefer. There would be few social benefits and substantial costs.

161. At the same time, in response to complaints, the Commission may devote resources to policing individual stations. In a society where governmental control over information is viewed as undesirable, there are also less perceptible legal costs to stations involved in interpreting conformance to Commission guidelines.

162. Since these quantitative programming guidelines impose costs on the Commission, radio stations, and the public alike, it is essential that we determine whether or not they actually achieve their public interest objectives.

163. In order to evaluate a regulation, it is necessary to articulate the exact public interest objective that the regulation was designed to achieve. For example, is the goal of existing informational programming regulations to increase the overall level of citizen awareness? Is it sufficient to increase the awareness of already relatively well-informed individuals? Or should greater weight be given to capturing that audience that does not receive any information from television or the print media?[168]

164. If radio is to remain a basic source of information and if a particular target audience is sought, then some strategies may be preferable to others, depending on audience traits. Consider news programming, for example. Do members of that target audience (a) shift from station to station in search of news? (b) shift from station to station to avoid news? (c) choose a station for reasons other than news programming and then just passively accept whatever news programming is provided by that station? (d) choose a station for reasons other than news programming and then actively and attentively listen to the news programming provided by that station? (e) have a favored program format, and choose among the various stations providing that format primarily on the basis of the news programming offered by the competing stations?

165. If (a) holds true, then government regulations requiring each and every station to provide news coverage would not increase consumer well-being. The only need would be some assurance that the overall market—rather than each individual station—provide adequate news coverage. The available data suggest that both in large markets, which generally have all-news stations and specialty news network affiliates, and in small markets, where most stations have very extensive news coverage, market forces already seem to be providing this.[169]

166. If (b) holds true, then no government regulation could be effective since the audience would not choose to listen to such programming anyway.

167. If (c) holds true, then minimum programming guidelines might increase public awareness, though it is not clear how much better informed these passive listeners will become since they may not analyze or use the news they do hear. Also, if the audience prefers the entertainment programming, the licensees might schedule the additional news programming during nonpeak hours.

168. If (d) holds true, then minimum programming guidelines might increase public awareness, if the radio stations otherwise would have provided less than the guideline level of programming. Again, any news programming motivated by the need to meet the guidelines rather than by actual consumer demand might well be broadcast during nonpeak hours when there are fewer listeners. Nonetheless, the more attentive the audience, the greater the potential social benefits from the regulation.

169. If (e) holds true, then those stations that are most responsive to listener wants with respect to news programming will gain audience at the expense of less responsive competitors. Minimum processing guidelines on all stations might increase the total amount of information provided in the market *if* the listeners would not otherwise demand that much programming. In that case, the alert station might try to schedule the unwanted programming during the least popular hours. Hence, audiences may only become minimally better informed.

170. A study performed by Frank Magid Associates for the Associated Press, entitled "Radio News Listening Attitudes,"[170] sheds some light on audience traits. The study covered the entire radio audience, not just a target audience. Table 9 summarizes the responses to a question on attitudes toward radio news. Respondents were asked to choose among four attitudes. 30% of the respondents indicated "News on the radio is important—I especially tune to a particular station to hear the news." This corresponds to our categories (a) and (e). 56.4% of the respondents selected, "When news comes on the radio, I pay attention to the news content." This would seem to correspond with our category (d), and perhaps partially with category (e). 10.1% indicated, "Radio news doesn't matter much to me—I pay little attention to the news or news content." This corresponds to our category (c). 3.2% chose "I dislike it when the news comes on the radio—I usually turn off the radio or switch stations when news comes

[166] *National Public Radio Annual Report, Fiscal 1978*, "Original Program Hours Produced or Acquired by Source," p. 55.

[167] *National Public Radio Annual Report, Fiscal 1978*, "Station Usage on NPR Programming, July-September 1978," p. 1–4.

[168] Should, indeed, radio be expected to fill this role if, as the Roper polls cited earlier suggest, the vast majority of citizens consider radio only a secondary source of news and public affairs information?

[169] See paragraphs 174 *et. seq., infra.*

[170] AP Research, 1979, 55 pp.

on." This corresponds to our category (b).

171. The Magid Study thus suggests that most radio listeners fit into our categories (a), (d) and (e). The effectiveness of minimum programming guidelines in increasing citizen awareness, then, will depend on (1) whether the guidelines require more news programming than would otherwise be forthcoming in the market, (that is whether the regulations are affecting programming decisions) and (2) the time of the day that additional news programming is broadcast (peak demand time or nonpeak time).

172. It may be possible to discern whether or not the existing regulations are in fact affecting programming decisions or whether market forces are the controlling factor. If most stations are providing more informational programming than is stipulated by the processing guidelines, that might suggest that market forces, not the guidelines, are the controlling factor.

173. There could be an additional regulatory factor operating, however. Licensees might choose to provide more informational programming than suggested by the guidelines in order to provide an "insurance policy" against comparative challenges or Petitions to Deny. Fortunately, it may be possible to separate these two motivations. Licensees programming for "insurance" rather than in response to audience demand are likely to schedule that additional programming during graveyard hours rather than risk losing audience during peak hours.

174. Some relevant data on the distribution of programming over the broadcast day are available on license renewal forms. All stations must provide data on the amount of nonentertainment programming provided during a composite week. These data are divided into three categories: "News," "public affairs," and "other." The "other" category is very broad, including such disparate areas as instructional, agricultural, and religious programming. With the data aggregated, we cannot distinguish among these elements in the "other" category. Unfortunately, we *cannot expect that each of these* elements has been equally affected by the minimum processing guidelines. For example, the amount of religious programming provided by a station is very unlikely to be affected by the existence of the guidelines. Other elements, however, such as instructional or agricultural programming, are more likely to be affected. We have therefore limited our analysis to the data on news and public affairs programming.[171]

175. Our concern is two-fold: (1) How much news and public affairs programming is being provided under the current regulatory scheme and how does this compare to the guidelines? and (2) during what time of the broadcast day is this programming being aired? Tables 10 A and B, 11 A and B, and 12 A and B present aggregate data, by market size, on the percentage of news and public affairs programming broadcast. Several generalizations stand out.

(1) In markets with eight or more stations, more than 75% of the stations broadcast more than 6% news and public affairs programming (6% is the current Commission guideline for news, public affairs, *and "other"* programming for FM stations).

(2) In markets with seven or fewer stations, over 96% of the stations broadcast more than 6% news and public affairs programming. More than 80% of these stations broadcast in excess of 10% news and public affairs programming.

(3) As market size increases, the percentage of stations providing 10 to 25 percent news (or news and public affairs) programming decreases, while the percentage providing more than 50% news programming increases. This suggests that in markets with one or more stations providing listeners a steady diet of news programming, demand for such programming from other stations falls. These other stations can offer specialized programming formats because listeners can always switch to a news format station when they want news.

(4) Excluding one and two station markets, the amount of public affairs programming provided falls greatly as market size falls, suggesting that this programming appeals to a minority audience, and such audiences can best be accommodated in large markets where individual stations seek small niches to serve.[172]

176. If these market forces are indeed present, it is useful to know how fully radio markets are served by news and public affairs-oriented stations. Table 13 provides data on the number of such stations in each large market.

177. The data indicate that virtually all markets with 16 or more stations are served by one or more news-oriented stations. This blanket news coverage by a single station is less frequent in smaller markets. When market size decreases to 11 stations, it is more likely than not that such markets will *not* have a news-oriented station. However, as market size falls, stations become increasingly likely to have 10 to 25% news programming (See Tables 11 A and B).

178. The existence of many news-oriented commercial stations and of specialty radio news networks suggest that radio news programming may be profitable in large markets. If news programming is as profitable as entertainment formats, one can expect it to be provided even in the absence of Commission regulation.

179. Similarly, news programming greatly exceeds Commission guidelines in small markets, strongly suggesting that news is being provided in response to market forces, rather than to regulatory pressures, in these markets as well.

180. Profitability data by program format are not directly available. The station logs submitted with license renewal applications, however, provide data on both commercial minutes and informational programming over the broadcast day. Presumably those broadcast hours with the most commercial minutes will be the most profitable (unless the programming during those hours is more expensive, or the rates per commercial minute are lower). If news and/or public affairs programming is equally frequent or more frequent during the peak advertising hours than during nonpeak hours, this would suggest that news and/or public affairs programming is at least as profitable as entertainment programming.

181. Tables 14 A, B, and C; 15 A, B, and C; and 16 A, B, and C summarize such data for 208 stations in a sample of large and small markets in Georgia and Alabama, the most recent license renewal group.[173] Table 14 indicates that prime commercial time for radio is drive time: 6 to 10 a.m. and 3 to 7 p.m., Monday through Friday.[174] Tables 15 A, B, and C show that although news programming is not distributed across the broadcast day exactly as commercial minutes are, there is more news programming during drive time than during non-drive time.[175] This is

[171] The data come from the latest renewal applications of each licensee. Since the renewal process is staggered, the data cover a three year time period, 1976–1979.

[172] Stations in very small markets may provide more local public affairs programming in an attempt to compete with distant signals.

[173] The sampling technique is described in the notes to each table.

[174] Data in Tables 14B and 14C indicate that commercial messages are less skewed toward drive time, especially afternoon drive time, in small markets than in large markets.

[175] The data in Tables 15A and 15B indicate especially high levels of news programming on

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strong inferential evidence that news programming is profitable and would be substantially maintained absent Commission guidelines.

182. Tables 16 A, B, and C suggest that public affairs programming is most common on Sunday mornings. This is a time period with few commercial messages.[176] With few exceptions, public affairs programming is minimal during other periods of the broadcast week.[177] It seems quite likely that, absent Commission regulations, many stations might not provide as much public affairs programming.

183. In sum, data on present programming and on consumer wants and habits suggest that absent regulation most stations would continue to provide news programming. It also is likely that in large markets a reduction in informational programming offered by some stations would not result in a lack of availability of such programming for the overall market.

184. If the fundamental criterion for meeting the public interest is responding to consumer wants, then the most important objective with respect to nonentertainment programming is to assure that when there is a significant demand for a particular type of programming a reasonable amount is available to those who want it. This suggests that the Commission might be concerned with the provision of such programming on a marketwide basis rather than on an individual station basis. The evidence that we have presented strongly suggests that on a marketwide basis there will be a significant amount of news programming in both large and small markets. There is no evidence of similar consumer demand for public affairs programming.

185. Local informational programming represents a subset of informational programming that may provide large social benefits and that deserves special attention. Within the print media, national and international news is covered by both newspapers and magazines, but local news coverage is generally limited to newspapers, often to only a single newspaper. Thus, citizens may be more dependent on the broadcast media for provision of local news than of national or international news.

186. News programming, however, is generally expensive to produce and therefore, purely on cost grounds, broadcast stations might have an incentive to pursue "blanket coverage" strategies that spread the fixed costs of program production over a larger audience, but may not foster local news coverage. Thus, one might expect a heavy reliance on network news production that emphasizes national and international news. The existence of scale production economies encourages local specialty stations to join with other geographically diverse stations with similar audiences to create specialty news networks. Because the audiences sought are geographically diverse, however, the news coverage will tend to be national or international, rather than local, in scope.

187. Nonetheless, there do exist strong countervailing market forces on the demand side that favor local news programming, especially in radio. In fact, almost 75% of all radio advertising is local advertising.[177A] As outlined earlier, many advertisers—particularly of local services—either may not be able to afford television or seek target audiences that can be reached efficiently only via radio. Many of these advertisers—for example, savings and loan associations—want to be closely identified with their local communities and therefore prefer to sponsor (and be associated with) local programming. Such programming is frequently of a news rather than an entertainment format. This is probably due to demand considerations. Audiences recognize the need for local news (that is, it is distinguishable from, not just a substitute for, national news), but there is no analogous demand for local entertainment (although local "personalities" often compete as announcers presenting the works of national recording stars).

188. The Magid study reveals substantial listener awareness of local news programming. Table 17 shows the relative importance of local news programming to listeners choosing among stations. Among listeners who prefer one of the four most popular formats (preferred by 75.2% of all respondents), good local news coverage was cited by 185 of 760 respondents (24.3%) as a reason that "best describes why (the particular station) is your overall favorite station."

189. Given that overall radio news programming appears to be profitable and that local news appears to be more important to radio listeners than network news (see Table 17), it seems likely that, absent Commission regulation, there would continue to be a substantial amount of local news programming. There is no similar evidence, however, for local public affairs programming.

190. Some of the mandatory community ascertainment requirements imposed by the Commission may also encourage local programming. Each station, after meeting with community leaders, must provide the Commission with a list of up to ten problems facing the community and examples of programming broadcast by that station in the past year that addressed those problems. Although some of the relevant programming would presumably fit the "local information" category, it is not certain whether all, some, or any of the programming was aired as a result of the regulation or would have been forthcoming anyway. Radio stations already seeking a particular specialized community will be sensitive to the informational needs of that community and may not require Commission oversight (and the attendant costs) to respond to those community needs. Similarly, those stations seeking a general audience will provide general informational programming, even in the absence of any specific regulation.

Failure to provide many voices

191. The Commission's concern with informational programming is not limited to its nature and amount. The concern also relates to the diversity of the programming provided. A possible corollary to the "well-informed citizen" argument has been advanced as follows: Society as a whole benefits when its citizens have access to many points of view (or diversity of opinion or "voices") on both problem-oriented and issue-oriented matters of public interest, and the unregulated market may not take into account those social benefits. Similarly, there may be social costs if certain voices are excluded and those costs also may not be taken into account in the market. Nonetheless, as in the case of quantity of informational programming, though potential market failure may exist here, it is not clear how significant it is or whether government regulation can improve the situation.

192. While attempting to avoid direct First Amendment issues, the

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Tuesday. This is the result of our sampling technique. For each station in the sample we chose one day from the composite log. Tuesday happened to be the day randomly assigned to the only all-news station in the sample. Since there were only a small number of stations operating during the graveyard shift, this station's programming made the averages for those hours particularly high.

[176] However, the lack of commercial messages may represent purposeful avoidance on stations that provide Sunday morning religious programming out of a moral rather than economic motivation.

[177] In very small markets, public affairs programming is generally more frequently broadcast, and more evenly distributed through the broadcast week. See Table 16C.

[177A] *See* Christopher H. Sterling and Timothy R. Haight, *The Mass Media: Aspen Institute Guide to Communication Industry Trends* (Praeger Publishers, New York, 1978), Table 303-B, page 129.

Commission has enunciated a number of rules and policies that touch, sometimes only tangentially, on the possible problem:

(1) The first part of the Fairness Doctrine as administered by the Commission requires all stations to provide some coverage of controversial issues of public importance.

(2) The second part of the Fairness Doctrine requires that, when a station covers controversial issues of public importance, it must provide diversity by presenting contrasting viewpoints.[178]

(3) Current quantitative processing guidelines for informational programming require *all* stations to meet minimum requirements or else justify the failrue to do so.

(4) Each station must meet certain community ascertainment requirements in order to learn about problems of importance to the community.

(5) EEO requirements and minority ownership policies have been set, with the intention in part of making all stations aware of and sensitive to minority needs and points of view.

193. These regulations and policies have varying degrees of effectiveness in pursuit of the public interest objective of providing many voices. A better key to attaining many voices, however, is a structural one—maximizing the number of stations in a market.

194. The second part of the Fairness Doctrine assures that contrasting views will be aired when controversial issues of public importance are presented. Listeners are more likely to get complete, nondistorted information, and unpopular opinions are more likely to be aired. Part 2 of the Fairness Doctrine reduces the substantial search costs that consumers bear in seeking out different sources in order to get different points of view on issues. As the number of stations in a market increases, however, the opportunity easily to receive different points of view increases, even without Part 2 of the Fairness Doctrine.

195. The first part of the Fairness Doctrine, requiring all stations to provide coverage of controversial issues of importance to the community, has been found by the Commission to have been violated in only one small market where an individual licensee refused to deal with a certain issue altogether.

196. Although the Fairness Doctrine requires stations to provide coverage of controversial issues of interest *to the community,* we have never defined the term "community" as it applies to fairness issues. In other contexts, however, we have defined "community" to include the entire service are of a particular station (which would in most instances include more than the city of license).

197. While we have accorded broadcasters broad discretion in choosing the issues to be covered, we suspect that our broad definition of "community" may have encouraged broadcasters to select fairness issues of broad appeal to the entire community, rather then more narrow issues that might be more important to the more limited audience that actually listens to the station. Thus, some stations may have avoided specialty news coverage (for example, Black or Spanish language news) and the result may have been redundant coverage of general news (that was already covered by other stations) at the expense of unique speciality news coverage. Yet the speciality audience is far more likely to be attracted to news that it considers relevant, so that the effective dissemination of information may fall. This would be especially troubling if the special audiences are nonusers of the print media.

198. The quantitative programming guidelines also may assure that more voices will be heard than in the absence of these policies. As the data presented in the previous section suggest, however, market forces may dictate the maintenance of most news programming even in the absence of regulation. In any case, it is not obvious that those stations that prefer *not* to provide news and public affairs programming do more than a perfunctory job of providing such programming—"rip-and-read" news and graveyard scheduling of public affairs programming, for example. Thus, the promised additional voice might not be very meaningful. It is also not clear that those stations that are not interested in news and public affairs programming would be offering different points of view. They may depend largely on news services that are already used by other stations.

199. The Commission's ascertainment rules were implemented to encourage programming that is responsive to diverse local problems and needs while avoiding direct Commission involvement in specific licensee program judgments. The intention has been that if station owners and employees follow ascertainment procedures, programming judgments would better reflect local problems and needs than would be the case if they relied solely on information from their ordinary business and social contacts. Hence, a wider spectrum of community problems might be addressed.

200. Because ascertainment is a procedurally detailed, but indirect, mechanism by which to expand program diversity, it is costly, but its effectiveness cannot be readily discerened. Licensees are required to gather certain demographic data about their communities, talk to community leaders, and provide a list of problems and issues of importance to the community. There are no *specific* programming requirements, however.

201. In large markets, where stations are increasingly following strategies of serving narrow audiences, many if not most stations will naturally air programs of interest to that special community without need of formal ascertainment procedures. Hence, ascertainment may not be necessary to produce programming responses to the important needs of specific groups such as Black, Spanish language and other foreign language speaking Americans, and women.

202. Since the implementation of formal ascertainment procedures in 1971, two important changes have occurred: EEO rules have been widely implemented, and stations have increasingly chosen strategies of seeking narrowly defined audiences. As a result of those developments, diverse community needs—including minority needs—are being better addressed. It appears that the ascertainment requirements that once provided broadcasters necessary guidance now may be superfluous to their task of determining community needs.

203. In addition, any possible benefits from ascertainment requirements must be weighed against the costs. The volume of information filed with the Commission by applicants and licensees, and the additional information that must be kept in local station public inspection files, indicate the substantial burden imposed on the industry by this requirement. The demands on Commission resources are also very high. As a rough indication, since the adoption of the initial Primer in 1971, the cases dealing with ascertainment have been so numerous that just the annotated index of cases covers almost 60 pages.[179] The bulk of these cases deal with purely mechanistic aspects of the formal ascertainment procedures.

[178] Because at least Part 2 Fairness Doctrine obligations appear to be mandated by Section 315 of the Communications Act, and because there is a great deal of uncertainty as to whether or not Part 1 obligations are required by statute, we do not believe that it would be desirable to undertake a significant change in our current Fairness Doctrine policies in this proceeding.

[179] Digest, Vol. 2, Second Series, Pike & Fischer Radio Regulation, paragraphs 53: 24(R)(6) and 53: 24 (Y)(1)–(18).

204. The cases reflect a substantial expenditure of resources in preparing and acting on petitions to deny, motions to request or enlarge issues, and adjudicatory decisions. Unreported are the thousands of letters sent while processing applications, contested and uncontested alike. We recongnize that many of these cases reflect legitimate complaints that licensees have not complied with ascertainment criteria.

205. It is not clear, however, how well these formal criteria improve consumer well-being. We are proposing to permit broadcasters to program exclusively for selected audiences since we suspect that licensees' own economic self-interests would encourage them to ascertain for those selected audiences, without our requiring detailed procedures for the *entire* community. We are now seeking comments to determine whether ascertainment procedures are worth the high cost involved.

206. In general the key to providing many voices remains the pursuit of policies that will maximize the number of stations on the air, coupled with the EEO and minority ownership policies (which will be discussed in greater detail below). These provide the greatest opportunity for increasing the number of voices in radio markets by expanding radio ownership and management beyond its present confines. It is clear that the most effective method of encouraging equal employment opportunity and minority ownership goals maybe to greatly expand the number of radio stations on the air and make it easier for minority groups to obtain new radio licenses or to buy existing stations.

Failure to account for distortions due to discrimination

207. If the market works, there should be competitive forces that put pressure on producers to be efficient so that producers can only afford to indulge their personal prejudices at their own peril. If the most qualified person is denied employment or promotion by one employer due to prejudice, then a competitor will take advantage of the situation, employ that qualified person, and reap the rewards in the marketplace. Hence, discrimination should not flourish in a competitive market.

208. If discrimination is systemic, however, fully ingrained in the market so that many if not most decisionmakers share the prejudice—then the discriminator will suffer no competitive disadvantage. The only parties adversely affected *directly* will be those discriminated against. Such institutionalized discrimination—whether against women, ethnic or racial minorities, or any other group—has not only moral, but also economic, consequences.

209. All markets, those for inputs into production (that is, labor, capital, materials) as well as those for final products, will function efficiently only if they are competitive. For markets to be competitive, participation (entry) should not be restricted (except to establish necessary minimal technical requirements for *all* participants and potential entrants). Discrimination places an artificial restriction on certain potential participants. With fewer individuals allowed to participate in a particular labor market, either those who are eligible will be able to demand higher wages than they otherwise could get or the quality of those hired will be lower than it could be.

210. The public loses from discrmination, because overpaid or lower quality employees can mean reduced public well-being. Either goods and services will be produced at higher cost than necessary, or some goods and services that consumers want and would be willing to pay for do not get produced.

211. More basically, the market system can achieve social well-being only if everyone can participate. Every individual must be free to offer his or her skills or other resources and receive commensurate payment for these in order to purchase goods and services. If any group is systematically discriminated against, the well-being both it and society at large derive from the market system is reduced.

212. In broadcast communications, systemic discrimination can have several consequences. Hiring or promoting on a basis other than skill level will obviously reduce product (in this case, program) quality. In addition, systematic exclusion of certain groups from decision making positions may reduce the likelihood that programming will be sensitive to the wants of those groups. Discrimination, then, may adversely affect program diversity.

213. An argument can be made that discrimination will not affect program diversity because, even if decisionmakers are all from a single homogeneous group and unaware of other community needs, they will still be responsive to diverse interests if they remain alert to market forces. That is, they will respond to audience size and demographics. The market takes as given, however, the distribution of income and wealth, and if past (and present) discrimination has caused certain groups to have little wealth and income, those groups will have small voices in the market. Therefore, their wants may remain underrepresented in current market allocations. In this case, the market may provide less than the optimal amount of "minority programming." [180]

214. To counter the market's inability to respond to systemic discrimination, the government has intervened through the enactment of equal employment opportunity laws. For most of the economy, these laws are administered by the Equal Employment Opportunity Commission. The FCC, however, has special authority to administer its own EEO rules for the broadcast industry.[181]

215. If the market may provide too little minority programming, the government has a number of potential ways to attempt to remedy the situation. EEO laws deal with present discrimination, but will have limited immediate effect on program content. In order to increase minority programming, the options available are the same as for increasing informational programming: Direct or indirect subsidization of minority programming or direct regulation (imposing minimum guidelines for minority programming). The Commission has chosen the former course. It has instituted policies that favor minority ownership and EEO affirmative action requirements, on the assumption that such measures will result in programming reflecting the needs and interests of minority groups. The effectiveness of this policy in achieving the Commission's public interest objective of diversity will depend in part on the ability and willingness of minority owners (and employees) to provide minority programming.

216. The alternative regulatory approach—imposing guidelines for minority programming—would require the same kind of monitoring costs that have been associated with informational programming guidelines. If there is no public policy argument that *all* stations in a market should provide minority programming, but only that each market should have a reasonable amount of such programming, the imposition of guidelines for each station would be misguided. Furthermore, it would impose the additional cost of government intrusion into programming and ultimately might not even be a true reflection of minority needs since it

[180] In the following discussion, "minority programming" is defined to be programming designed to meet the special wants of those groups that have been discriminated against.

[181] *Nondiscrimination in the Employment Policies and Practices of Broadcast Licensees*, 60 F.C.C. 2d 226 (1976).

would be the broadcaster rather than the minority listener making the choice.

217. EEO rules on nondiscrimination in employment practices have been in effect for ten years now. Our annual employment statistics show that the employment of minorities and women in the broadcast industry has increased.[182] Equally important, the amount of minority programming in radio has increased dramatically.

Commercial practices

218. The Commission has imposed quantitative processing guidelines on the use of broadcast time for commercial messages based on the belief that the public airwaves should not be unduly used to further private commercial interests.[183] The underlying presumption is that entertainment and informational programming better serve the public interest than do commercial messages.[184] This is, of course, a value judgment. How many commercial minutes represent "too much" is a noneconomic judgment. There are no objective standards on which to base the decision.

219. Existing guidelines therefore cannot be subjected to any objective test. It is worth investigating, however, whether or not, absent the regulation, the market would have yielded more commercial minutes. Theory suggests there are strong limiting forces in the market.

220. Clearly, up to some point stations can increase their revenues if they increase the number of commercial messages broadcast. Advertising rates, however, depend on audience size and characteristics. If audiences prefer programing to commercial-messages, they will desert stations that overcommercialize. This may be especially true of higher income audience members (those who may be most coveted by advertisers) who have more entertainment options availabe. Hence, audience pressure exists to limit commercial messages. At the same time, advertisers prefer that their messages not be lost among the exclusivity or totally aviod overcommercialized stations. Hence, sponsor pressure exists to limit commercial messages.

221. Absent a freely functioning market, it might be impossible to determine exactly how many commercial messages the market would produce. Obviously, different markets would yield different results. Where there are very few broadcast outlets, stations might be able to sue their monopoly power to extract extra revenues from overcommercialization. In these small markets, however, there may be few advertisers. In markets with many stations, the audience will have options if a particular station chooses to schedule many commercial messages, and advertisers can choose less cluttered stations. Hence, in these markets, overcommercialization might not be a threat.

222. Fortunately, some data are availabe to test this theory. The actual commercial minutes reported by stations in the composite week logs of their license renewal applications can be compared to the Commission's guidelines. If in most or all hours stations in particular markets do not air as many commercial minutes as specified in the guidelines, this would suggest that market forces place a stronger restriction on commercial time than do the Commission's guidelines.

223. Data on stations in Georgia and Alabama are available from composite week logs filed with the lecense renewal applications. We have collected data from a sample of stations in large and small markets. Table 18 summarizes the information on the incidence of commerical time exceeding the Commission's 18 minute (1080 seconds) per hour guideline. As the table indicates, the frequency with which the guidelines were met or exceeded generally was very low for large markets, increased somewhat for moderate sized markets (with 3 to 8 stations), and was very low again for small markets.[185] Notetheless, the overall incidence of "overcommercialization" was quite low, even in the "high incidence" markets.

224. An argument can be made that stations purposely remain below the guideline, rather than at the guideline, in order to provide an "insurance policy" against petitions to deny or comparative challenges. Such behavior may be rational, but stations are unlikely to unduly restrict commercial time as that would prove to be a very costly insurance policy indeed.

225. To try to determine whether this insurance policy behavior is limiting commercial time or whether market forces are responsible, we collected data on the incidence of different amounts of commercial time per hour. Table 19 summarizes the results. Note that 950 seconds is 2 minutes, 10 seconds below the Commission guideline. It is likely that if licensees presently follow the "insurance policy" strategy, but would, absent Commission regulation, exceed the guidelines, they might reduce their commercial time to 950 second an hour which is more than 10% below guidelines, but would not sacrifice more than that for insurance. Hence, a high incidence of commercialization between 950 and 1080 seconds per hour might suggest widespread use of the insurance policy strategy. If most commercialization falls below 950 seconds, then market forces are probably the determining factor. As Table 19 shows, there is very low incidence of commercialization at 950 seconds or more (though it is somewhat more frequent in the small to moderate-sized markets). This suggests that market forces, rather than Commission regulations, are primarily responsible for the present level of commercialization, and that these forces do not allow overcommercialization.

226. There is an additional set of evidence suggesting that market forces will impose restrictions on the amount of commercial messages broadcast. Many if not most FM stations air far fewer commercial messages than do AM stations,[186] and yet (or perhaps partially

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[182] *Id.*

[183] The processing guidelines are set out above in note 92, *supra.*

[184] Commercial messages clearly provide useful services to listeners. They are an important source of information about goods and services that listeners consume. Without radio advertising, producers of these goods and services would have to use alternate—perhaps less efficient—means of communicating their messages. Although arguably some of these commercial messages are primarily "persuasive" with little informational content, many radio messages provide important price and availability information. For example, savings and loan associations use radio advertisements to inform listeners of the availability of higher interest rates; local retailers inform listeners of special sales, sometimes providing specific price information; rock and classical music stations advertise concerts, efficiently reaching that group of the population most likely to be interested in the concerts. Indeed, the trend in radio toward matching specialty audiences with specialty advertisers represents the exploitation of a highly efficient means of information flow. Listeners of specialized stations know that the commercial messages will provide a certain type of information and if that information (e.g., concert announcements) is important to them, then they can gain valuable information at a low search cost. The information may not be available at a local level in alternate media such as specialty magazines, which tend to be national. Commercial messages also allow producers to inform mass audiences about the introduction of a new good or service. Without access to the media, or with restricted access, it would be more difficult for new entry to take place and markets would become less competitive, raising prices to consumers.

[185] Although theory might suggest that licensees in very small markets, with few competitors, might have a greater opportunity to overcommercialize, they generally cannot exploit the situation due to (1) a lack of demand by advertisers for airtime, since these markets are small, and (2) the competition for listeners from distant signals they may have few commercials. In moderate sized markets, there may also be distant signals, but demand for advertising time may be greater and therefore more commercialization will occur.

[186] In news release number 108/79, entitled "Code Claims Radio Stations Carry Fewer Ads Than FCC Endorses," The National Association of Broadcasters presented the results of a study on the

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as a result) FM is far more viable today than it ever has been previously. Indeed, a growing number of FM stations in large urban markets present (and heavily promote) commercial-free hours or entire evenings of programming. Clearly, these stations believe that consumers do react positively to reduced commercial time.

227. It thus appears that at present the Commission's guidelines are unnecessary in that competitive forces in large markets and the lack of demand in small markets dictate even lower levels of commercialization. It is possible that, in the future, demand for advertising time will grow faster than supply (or than the demand for programming) and the market might then yield more commercial minutes, exceeding present guidelines.[187] In this situation, however, more radio stations could be supported and pressures would build either to expand the amount of spectrum available for broadcast radio or reduce the spacing between AM stations and/or reallocate FM more efficiently. In the iterim guidelines should be removed.

Other potential bases for regulation

228. There are several other areas in which radio markets potentially may fail to perform efficently, and that therefore might necessitate government regulation. These include the failure to provide sufficient controversial programming, the failure to provide accurate consumer information, and the failure to account for owners' nonbroadcast market motivations. These will not be addressed in this Notice because they are not germane to the Commission rules and policies under scrutiny here. Where these potential market failures underlie other Commission rules or policies, however, they will be discussed in future Notices.

229. Similarly, there are other Commission rules and policies, akin to the processing guidelines on commercialization, that are not based on any market failure, but rather are based on non-economic (social or moral) value judgments. These include policies on licensee character, on certain intra-industry conduct such as hypoing and fraudulent billing, and on programming taboos such as obscene language and lotteries. These, too, will be addressed in future Commission Notices.

IV. Options for Elimination of Current Programming, Ascertainment, Commercial, and Related Requirements

230. It is clear that major technological, social, and structural changes in or affecting the broadcast radio industry oblige the Commission to re-evaluate its current regulatory scheme. The available evidence suggests that significant deregulatory steps might be appropriate. As there are a variety of ways to pursue such deregulation, we are setting forth a number of affirmative proposals.[187A] While we currently have a preference for a certain course of action, which is set forth in the next section, comment is invited on all of the alternatives set forth herein. Parties should feel free to propose alternatives not set forth in this Notice so long as they are limited to the areas under consideration. Parties should also feel free to submit any additional empirical information that will help the Commission evaluate the merits of the attention on the validity of the empirical information set forth above that serves as the underlying justification for many of the options presented here and to submit any additional empirical information that will help the Commission evaluate the merits of the alternatives.

A. Nonentertainment Programming

231. The Commission's current requirements for nonentertainment programming to be aired by radio station licensees are not fixed by a rigid formula, either in terms of a requisite number of hours or percentage of broadcast time. In a delegation of authority to the Broadcast Bureau, however, certain processing guidelines are set forth.[188] Should a licensee's programming proposal or profile fall below those guidelines, the application is not automatically dismissed; rather, the Bureau cannot routinely grant the application pursuant to its delegated authority. Instead, it must be brought to the attention of the full Commission.

232. Additionally, we require licensees to present programming to meet needs and problems discovered through ascertainment but, again, do not specify what amounts of such programming must be presented. In place of quantitative standards we proceed on more or less a case-by-case basis in evaluating stations' performance with regard to programming resulting from ascertainment.

233. A number of alternative approaches are available by which our current nonentertainment rules and policies can be modified or eliminated. These alternatives are as follows:

(1) The Commission could remove itself from all consideration of the amount of nonentertainment programming furnished by commercial broadcast radio licensees. Under this alternative, the marketplace would generally determine what levels of such programming would be presented.

(2) The Commission could relieve individual licensees of any obligation to present nonentertainment programming but would, instead, analyze the amounts of such programming on a marketwide basis. If the amount of nonentertainment programming presented in a particular market fell below a certain amount, the Commission would then take action to redress the deficiency.

(3) The Commission could free licensees of any specific responsibilities with respect to nonentertainment programming (and ascertainment and commercial minutes), but would require licensees to show, if challenged upon renewal, that they were serving the public interest. Marketwide criteria would be used for such evaluation.

(4) The Commission could impose quantitative programming standards for each nonentertainment programming category. Such quantitative standards could take the form of either a minimum number of hours per week that would have to be presented for each category

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amount of commercial messages broadcast by commercial radio stations. Among the results was the finding that most stations in a sample of 473 AM stations offered between 9 and 18 minutes of commercial messages per hour between 6 a.m. and 7 p.m., on Thursdays and Fridays; most stations in a sample of 304 FM stations had between 3 and 9 minutes of commercial messages per hour during the same time period.

[187] Even if the market were to yeild "too much" commercialization, there could be great costs associated with imposing guidelines. If commercial time is restricted, demand will push up the price of that time, and some advertisers will be excluded from the airwaves. Since the fee paid to a station by an advertiser for commercial time is independent of the number of units of the advertised product sold by the advertiser, the costs of advertising per unit sold will be lower for larger, entrenched firms than for small, new entrants. Restrictions on commercial time may, therefore, impose costs more heavily on new competitors than on dominant firms and the degree of competition in these markets might suffer.

[187A] None of the proposals made in any of the areas under discussion pertains to noncommercial radio. Noncommercial licensees face different incentives and perform under a different statutory mandate than commercial licensees, and therefore the analysis performed in this Notice is not directly applicable to noncommercial radio. We shall, however, address the issues of ascertainment and nonentertainment programming as they pertain to noncommercial radio in a separate notice.

[188] 47 CFR 0.281(a)(8)(i)—Commercial AM and FM proposals for less than eight and six percent, respectively, of total nonentertainment programming; commercial TV proposals (except those made by UHF stations not affiliated with major networks) which project for the hours 6:00 a.m. to 12:00 midnight less than the indicated percentages in one or more of the following categories: five percent total local programming, five percent informational (news plus public affairs) programming, ten percent total nonentertainment programming.

of programming time that each station would have to devote to such category.

(5) The Commission could impose quantitative standards, as above, but instead of setting such standards, in terms of hours or percentage of time devoted to each category, could measure the adequancy of the programming on the basis of each station's expenditures thereon. This could take the form of the Commission's mandating a certain proportion of revenues or profits that each station would have to reinvest in nonentertainment programming.

(6) The Commission could establish a minimum fixed percentage of local public service programming that would have to be presented. This percentage could be met by the broadcast of any of the following alone or in combination: Local news, local public affairs, local public service announcements, community bulleting boards, or any other locally produced nonentertainment programming demonstrably related to serving local community needs. The meeting of this minimum percentage would be a *sine qua non* of license renewal.

None of these options would alter the Fairness Doctrine responsibilities of licensees.

B. Ascertainment

234. In paragraphs 29–40, above, we noted that our ascertainment requirements are set forth in policy statements rather than being specified in rules. Our rules do contain reference to ascertainment, however, principally with regard to the Broadcast Bureau's delegation of authority [189] and to licensees' public file obligations.[190]

235. We believe that there are four options that warrant consideration with regard to ascertainment. They are:

(1) To eliminate both the ascertainment procedures and the general ascertainment obligation and to leave it to marketplace forces to ensure that programming designed to meet the needs and problems of each station's listenership is supplied;

(2) To require ascertainment to be conducted by licensees but to permit them to decide in good faith how best to conduct that ascertainment without formalized Commission requirements;

(3) To retain our ascertainment requirements, but in a simplified form; or

(4) To retain our ascertainment requirements as they currently exist.

C. Commercial Practices

236. Our principal reference to commercialization appears in § 0.281 of the Commission's rules.[191] That section merely sets commercial limits that, if an applicant proposes to exceed, prevent the Broadcast Bureau from routinely granting an application pursuant to its delegation of authority.

237. The range of our options with regard to commercial practices include the following:

(1) We could eliminate all rules and policies dealing with the amount of commercial time and leave it to the marketplace to determine what levels of commercialization would be tolerated;

(2) We could set quantitative standards that, if exceeded, would result in some sanction being imposed against the licensee;

(3) We could eliminate all rules specific to individual licensees, but intercede if heavy levels of commercialization occurred marketwide; or

(4) We could retain quantitative guidelines but only with regard to the Broadcast Bureau's delegation of authority.

D. Program Logs

238. The Commission's requirements for program logs for AM and FM radio stations are set forth in §§ 73.1800 and 73.1810 of the Commission's rules. Because our program logging requirements are, in part, intended to assure documentation of licensees' efforts in providing nonentertainment programming and of their commercial practices, changes in our policies and rules in these areas may bring into question the need for retention of these rules. Accordingly, should we, as a result of this proceeding, eliminate nonentertainment programming requirements and commercial "limitations," we may also find the elimination or modification of our program log requirements to be warranted.[192] On the other hand if, as a result of this proceeding, a higher showing is required of members of the public challenging a station's programming performance, it may be unreasonable to permit the elimination simultaneously of the records necessary to substantiate such a claim.

239. Three options present themselves in this regard. In the event that our nonentertainment and commercial rules and policies are eliminated or modified in this proceeding, we could:

(1) Eliminate the need for AM and commercial FM stations to keep program logs;

(2) Eliminate our program log requirements but require any AM or commercial FM licensee keeping records of its programming or commercial schedules for its own purposes to make these available to the public in accordance with the procedures currently outlined in § 73.1850 of the Commission's rules and discussed in the Public and Broadcasting Procedural Manual, Revised Edition; or,

(3) Continue our program log requirements as they currently exist.

240. The alternatives set forth above with regard to all of the subject areas are not exclusive. Although in the next section we set forth our current preferences, comment is invited on any or all of the above proposals. Additionally, comment is invited on any alternative not set forth herein but which it is felt we should consider (e.g., requiring radio stations to keep records concerning programming aired but without specifying any particular format that such records would have to take). Any such new proposals should, however, be limited to the areas under consideration in this proceeding.

V. Preferred Options

241. Our ultimate goal in this proceeding is to maximize the benefits of radio services to the public. If that goal can be achieved with a minimum of regulation on our part, we will increase the public benefit, for then we will have reduced the delays and costs of regulation without sacrificing service to the public. From this perspective, the option of eliminating the Commission's ascertainment obligations as well as the guidelines on nonentertainment programming and commercial matter is the most attractive. It offers the potential of a well-served public at greatly reduced regulatory cost. Moreover, the data presented in the previous section provides a strong indication that the marketplace can in fact be responsive to the public's needs and wants without Commission intervention. In other words, the evidence suggests that the Commission's statutory responsibility to protect the public interest can be honored if the Commission largely relies on the discretion of its broadcast licensees in the areas of ascertainment, nonentertainment programming, and

[189] See § 0.281(a)(8)(ii) which excepts from the Broadcast Bureau's delegated authority cases where there are substantial ascertainment defects that cannot be resolved by staff inquiry or action.

[190] See §§ 1.526(a) (11) and (12) which require licensees to place documentation of their ascertainment efforts into their public file.

[191] See note 92, *supra.*

[192] Additionally, as Emergency Broadcast System (EBS) log entries currently may be made in the program logs, it will be necessary to require commercial AM and FM stations to make such entries in their operating logs, necessitating the amendment of § 73.1820, as well.

commercial matter.[192A] If we should ultimately adopt this approach, however, we would not completely walk away from broadcast regulation in these areas. If we found that the marketplace had failed to serve the public adequately, we would have to be prepared to take appropriate action to remedy the situation. In addition, we must always keep in mind the Fairness Doctrine [192B] and how it will be enforced under the new regulatory procedures.

242. The approach we propose here is consistent with Congress' intent to permit commercial broadcasting to develop with the widest possible journalistic freedom consistent with its public obligations.[193] Furthermore, it is entirely consistent with Congress' intent that the Commission have sufficient flexibility, through the "supple instrument" of the public interest, to respond to the rapid and dynamic changes that have characterized broadcasting throughout its history. We believe it would be worthwhile to set forth in some detail a rationale for taking the maximum deregulatory steps consistent with our public interest responsibilities. We hope hereby to facilitate public comment which will assume a complete record and address the central legal and factual issues presented by this and related proposals.[194]

Nonentertainment programming

243. We recognize the potential for radio markets to provide too little informational programming, but believe that the evidence indicates that the marketplace is likely to nonetheless serve consumer desires more efficiently than any regulatory alternative we can envision. We are concerned that the intrusion of the Commission into the market may result in the implementation of guidelines across markets that can hinder broadcasters in responding to the wants of their own listening audiences. If the guidelines are set too low for a particular market, they will sumply be redundant; if too high, they may coerce the licensee into providing nonentertainment programming that the public does not want at the expense of preferred programming, thereby reducing consumer well-being.

244. The other specific proposals covering nonentertainment programming each have drawbacks that must be addressed. Guidelines established for individual components or categories of nonentertainment programming (proposals 4 and 5) would further limit the ability of licensees to respond to the particular demands of their own communities. For example, a station facing a high demand for news programming but low demand for public affairs programming might find itself forced to produce more of the latter at the expense of the former, and also at the expense of listeners whose preferences would be disregarded.

245. Tying expenditures on nonentertainment programming to overall station revenues or profits (proposal 5) threatens to undermine the causal link between market forces and responsiveness to consumer wants. There is good reason to believe that licensees maximize their potential to earn large revenues and profits when they accurately gauge and serve the wants of their community. If those wants include significant amounts of nonentertainment programming then proposal 5 will not cause harm. But if those wants tend not to include such programming, then proposal 5 may force the licensee to divert resources from programming preferred by listeners to that which is less preferred. This would run counter to the public interest criterion of satisfying consumer wants.

246. Guidelines aimed at individual stations (proposals 4, 5, and 6) fail to recognize that any evaluation of nonentertainment programming can appropriately be made only on a market-wide basis since listeners have available to them the sum of the programming of stations in the market, not just the programming of individual stations. Proposal 6, for example, fails to take into account that specialized communities exist that are not geographically localized and might be more interested in specialized news and public affairs programming that is national in scope than in general local programming. If there is a substantial demand for the local programming sought in Proposal 5, then so long as that demand is met by other stations in the market, it may be unwise to force the station catering to a specialized audience to provide similar coverage. If there is no demand for local programming, no station should be required to provide the programming.

247. Marketwide guidelines (Proposal 2), though superior to individual station guidelines in that they allow individual stations greater flexibility in responding to listener wants, also have drawbacks. Percentage guidelines that might be appropriate in one market might not be in another market. Consumer demand for informational programming will depend on a number of factors, including the heterogeneity or homogeneity of the population (by ethnic or racial composition, by age, by income distribution, by white collar/ blue collar, and the like). If the industrial base of one community is tied primarily to a single industry (e.g., farming, automobiles) then enough people in that community might be interested in specialized news or public affairs coverage of that industry to support such programming. In communities with diverse economic bases, there may be no analogous demand. In other words, rigid bureaucratically determined guidelines cannot respond well to these differences.

248. Proposal 3 places a heavy burden of proof upon licensees and, more importantly, forces the Commission to assess each individual station's programming rather than leaving that task to the listening audience—the marketplace. Under proposal 3, the Commission either would face the alternative of evaluating the claims of each licensee on an *ad hoc* basis, which could be unduly burdensome for the Commission, or falling back to the type of guidelines that we are attempting to eliminate.

249. The data strongly suggest that no regulatory alternative would be likely to satisfy consumer wants as well as the market solution offered in proposal 1. Under that proposal, the Commission would remove itself from all consideration of the amounts of nonentertainment programming furnished by radio broadcast licensees.[194A] In that event we would expect that market forces operating in both large and small markets, as indicated elsewhere, in conjunction with Commission policies, rules and regulations, covering structural matters (e.g., EEO, multiple ownership, AM-FM duplication, minority ownership and the like) will create a marketplace that is more reflective of significant consumer demands than standards imposed by the Commission.

250. As mentioned above, adoption of the first option would not completely remove the Commission from broadcast regulation in the areas of ascertainment, nonentertainment programming, and commercial matter. We would still consider petitions to deny, complaints and other information to guard against marketplace failures. This potential for

[192A] If additional data not currently available were to suggest a different policy conclusion, we would be responsive to such data. We therefore encourage all parties to provide any relevant data during the comment period.

[192B] *Fairness Report*, 48 FCC 2d 1 (1974), *recon.*

[193] *Columbia Broadcasting System, Inc.* v. *Democratic National Committee, supra.*

[194] *See* paragraphs 51–54, *supra.*

[194A] Except as discussed *infra*, at paragraphs 253–264.

Commission intervention is discussed in greater detail below in the section on petitions to deny. Moreover, proposal 1 does not contemplate any change in our enforcement of the Fairness Doctrine. That doctrine requires broadcasters to provide coverage of controversial issues of public importance and to ensure that the coverage is balanced with contrasting views. There is some question as to whether adoption of proposal 1 would create any problems in fairness enforcement and, if so, how those problems should be resolved. We invite parties to comment on that matter as well as the entirety of our reasoning for believing that option 1 may provide the greatest benefits to the public.

Ascertainment

251. Two of the principal factors leading to this review of our regulations were the significant increase in the number and competitiveness of radio stations and the tendency of more and more of these stations to cater to specialized audiences. Although the Commission has maintained formal ascertainment requirements, a number of factors strongly suggest that the continuation of these requirements may be unnecessary. In large markets, the matching of specialized audiences to particular stations, the greater fulfillment of minority interests, and the diversification that other Commission policies foster appear to remove the necessity for the formalized ascertainment procedures that have developed over time.

252. Although small market stations may have few radio competitors for commercial messages, they must compete with distant radio signals for listeners. Virtually all communities receive one or more distant signals and most small communities (with only one or two local stations) receive more than half a dozen. The competitive edge that the local small market station may enjoy is identification with and responsiveness to the local community. The licensee can usually be expected to know his community. This is evidenced by the large amount of news and public affairs programming provided by small radio markets.[194] Market forces exist that motivate the small market licensee to be aware of his local community's needs absent any formal ascertainment procedures.

253. Additionally, it is apparent that these mechanical procedures are costly and impose unnecessary burdens upon radio licensees. Parties, ranging from the United Church of Christ to the National Association of Broadcasters, have also questioned the need for some or all of our formal ascertainment requirements.[195]

254. Thus, it may no longer be in the public interest to require each licensee to ascertain the problems and needs of all significant groups in his community. Rather, since broadcasters appear to aim their programming at more specific groups, the ascertainment of all groups in a mechanical procedure may be wasteful.

255. With regard to the ascertainment of the needs of a licensee's particular audience, Commission requirements may be similarly unnecessary as the licensee has an economic incentive to be aware of, and responsive to, those needs in order to keep and increase his audience. We believe that such incentives will result in some form of ascertainment taking place even in the absence of a Commission requirement. Structural regulations by the Commission is intended to assure diversification in broadcast employment and ownership, giving many voices access to the radio medium. The effects of diversification, together with broadcast incentives to discover and serve the needs of their audiences, would probably generate market forces responsive to significant demands for programming. Therefore, as ascertainment was designed in part to ensure that such programming would be provided, these marketplace forces may render continuing government regulation to that same end unnecessary. Accordingly, we believe it may no longer be in the public interest to require AM and commercial FM broadcasters to ascertain the needs and problems of their community, and we therefore propose elimination of both the formal procedure and the ascertainment obligations itself.

256. None of the other alternatives presented is as attractive. To retain our current formalized ascertainment procedures would, as noted above, maintain a costly and probably unnecessary burden upon licensees. To retain ascertainment requirements but to modify them to make them less formal might only lead to a situation similar to that which obtained prior to 1971. That is, so many questions could arise that we would likely be required to again formalize the procedure. Accordingly, that choice could easily lead us back to ascertainment requirements similar to those currently in place. The simplification of the ascertainment procedures similarly could leave many resolved problems that might well lead to the imposition of requirements akin to those currently in force.

Commercial practices

257. Existing guidelines on commercial minutes simply represent Commission value judgments. They are not based on any objective measure of consumer well being. The same would be true of any system of commercial guidelines, whether imposed marketwide or on individual licensees. Listeners seem to be quite responsive to nonpreferred programming; they usually tune it out for other programming or for non-radio alternatives. It therefore seems to us that individual radio markets can better determine appropriate levels of commercial messages than can the Commission. Indeed, present levels are far below Commission guidelines. We therefore prefer to eliminate all rules and policies dealing with commercial time and leave it to marketplace forces to determine what levels of commercialization would be tolerated. Again, we believe that those forces will be sufficient to deter abuses.

Program logs

258. With regard to the maintenance and retention of program logs, we believe that our other proposed actions could well make a requirement that radio stations maintain, and retain, program logs unnecessary. Since the object of deregulation is to remove unnecessary regulation, the public interest might best be served by the elimination of program log requirements for broadcast radio stations from our rules. (See Appendix B.) We do propose to adopt a rule, however, requiring stations which, for their own reasons or business requirements, elect to maintain a record of commercials and/or programming aired to make that record available for public inspection in accordance with current practice. This would represent a minimal cost to licensees but would provide the public with valuable information.

Procedural changes

259. The actions that we are proposing will affect current practice relating both to petitions to deny and to comparative

[194] See Tables 10A, 10B, 11A, 11B, 12A, and 12B, *infra*.

[195] See for example, Office of Communications of the United Church of Christ, Memorandum to Federal Communications Commission Re: Radio Deregulation, May 31, 1979, pp. 1–2. That document also contained an appendix listing 113 participant organizations and individuals that joined the Memorandum under an umbrella known as the "Telecommunications Consumer Coalition." See also National Association of Broadcasters Petition for Rule Making, In the Matter of Deregulation of Radio: Repeal of Delegations of Authority on Commercial Standards and Nonentertainment Programming, Program Logging Rules and Formal Ascertainment Requirements for Renewal Applications, and Other Relief for Radio Stations.

hearings. We therefore propose certain procedural modifications and invite comments upon these proposals as well as any alternatives that we may have omitted.

Petitions to deny

260. Section 309(d)(1) of the Communications Act states that "any party in interest may file with the Commission a petition to deny any application."[196] Petitions to deny must contain "substantial and specific allegations of fact which, if true, would indicate that a grant of the application would be *prima facie* inconsistent with the public interest."[197] Where there are substantial and material questions of fact present or where we are unable to find that a grant of the application would be consistent with the public interest, we must designate the application for hearing.[198]

261. Among the grounds currently available by which petitioners may challenge applications are the levels of nonentertainment programming and commercials and the applicant's ascertainment efforts. Obviously, should we adopt the proposals made herein, these would no longer be available as grounds upon which to base a challenge to commercial AM and FM applications. Petitioners will still be able, however, to base petitions upon EEO violations, Fairness Doctrine violations and such other grounds as are currently, and will remain, available to petitioners. Additionally, in this regard, we note that discrimination in the provision of programming, especially where racial or sexual discrimination is involved, remains forbidden. Our ending of ascertainment obligations does not change our prohibition of such discrimination in programming. Thus, under our proposal, licensees will still be held individually responsible for the operation of their stations and petitioners will still have access to the petition to deny process.

262. Although levels of nonentertainment programming and commercials, and ascertainment efforts will no longer provide grounds for petitions to deny against individual stations, the Commission will not completely absent itself from consideration of these factors. We expect and encourage the public to keep the Commission informed as to how well the marketplace is performing. Based upon complaints from the public, we will monitor market performance. Should complaints from the public result in data suggesting that the market is failing in the areas that we propose to deregulate, we will further investigate and, if warranted, take whatever actions are required by the public interest to correct the situation. For instance, if we discover that the marketplace is failing in radio markets of a certain class (e.g., markets with less than four stations) we would consider fashioning relief applicable to such markets. In this regard, it is appropriate at this point to refer to the recent ruling of the United States Court of Appeals for the District of Columbia Circuit in *WNCN Listeners Guild* v. *Federal Communications Commission*, No. 76-1692 (D.C. Cir. 1979). It appears that the court's primary concern in that case, which involved the question of format change, was that the Commission be prepared to intervene in the marketplace in those rare instances in which the market fails to satisfy consumer wants. Although we do not want to prejudice our position in that matter here, we do believe that all of our proposals in this notice include the opportunity for Commission intervention should the market fail to satisfy consumer wants. In this regard, we specifically solicit comments relating to what method the Commission should use to determine whether or not such a failure has occurred.

Comparative hearings

263. One of the most vexing problems that we face in taking the proposed actions is the effect that such actions will have upon comparative hearings. In choosing among competing applicants in broadcast license proceedings, the Commission is guided in the exercise of its authority by the "public interest, convenience, or necessity." To make such a determination in the case of competing applicants for a broadcast license, it is necessary for the Commission to decide which of the applicants can render the best practicable service to the community.[199]

264. The Communications Act does not supply guidance, however, as to what factors we should weigh in making such a determination. Rather, the Commission has been left broad discretion to develop relevant criteria to be used in determining which mutually exclusive applicant would better serve the public interest. Accordingly, the Commission has been free to choose those criteria that it has reason to believe would serve the purposes of the Act.[200] As has recently been stated:

> In granting broadcast licenses the FCC must find that the "public convenience, interest or necessity will be served thereby." 47 U.S.C. 307(a). Within these broad confines, the Commission is left with the task of particularizing standards to be used in implementing the Act.[201]

265. The criteria that the Commission presently uses were developed through a series of comparative hearing decisions and were set forth in the Commission's *Policy Statement on Comparative Broadcast Hearings.*[202] The Commission is not bound, however, to maintain these comparative criteria forever. It is generally recognized that the Commission requires, and under the Communications Act has, the flexibility to adapt its regulations to changing circumstances.[203] Indeed, our comparative criteria have already undergone numerous changes since the Commission's formation. For example, at one time the Commission agreed to review all program proposals, because it believed that such review would facilitate a choice of the best applicant.[204] The Commission later concluded that, at least in initial licensing proceedings, consideration of program proposals was neither easy nor fruitful since an applicant could always make a "blue sky" proposal. The Commission therefore decided that it would no longer normally designate a comparative issue on program proposals. Instead it was decided that if an applicant could show that its proposal was significantly different, and showed a superior devotion to public service, it could petition for the addition of an issue. Thus, while not abandoning its commitment to public service, the Commission concluded that this commitment would not be compromised if it did not automatically consider program proposals.[205]

266. It is clear that the Commission has the authority to decide what issues will be relevent in comparative proceedings and to modify its opinions when circumstances dictate. If we adopt the proposals made herein, or variants thereof, however, we will be faced with the problem of articulating the basis for the evaluation of competing applicants.

[196] 47 USC 309 (d)(1).

[197] *Columbus Broadcasting Coalition* v. *FCC*, 505 F. 2d 320, 323 (D.C. Cir. 1974).

[198] 47 USC 309(d)(2).

[199] *Federal Communications Commission* v. *Sanders Bros. Radio Station*, 309 U.S. 470, 475 (1940).

[200] *Johnston Broadcasting Co.* v. *Federal Communications Commission*, 175 F. 2d 351, 357 (D.C. Cir. 1949).

[201] *National Black Media Coalition* v. *Federal Communications Commission, supra*, page 581.

[202] 1 FCC 2d 393 (1965).

[203] *National Broadcasting Company* v. *United States, supra.*

[204] See, for example, *Plains Radio Broadcasting Co.* v. *F.C.C.*, 175 F. 2d 359, 362 (D.C. Cir. 1949).

[205] *Policy Statement on Comparative Broadcast Hearings, supra* at 397–398.

One option we are considering is that the Commission not consider as a matter of course program performance or commerical practices in a comparative prodceeding. It might be unfair to allow a broadcaster maximum discretion to respond to market forces and then place the broadcaster at a comparative disadvantage if we should decide in a *post facto* fashion that the market forces produced an unsatisfactory situation.[205A] Under an alternative proposal arising with respect to comparative renewal proceedings, an incumbent licensee might be allowed to voluntarily ask for Commission consideration of its nonentertainment programming *or* of its entertainment programming as a basis for finding that the licensee's past service is sufficiently meritorious to overcome a challenger's advantages on other grounds. In considering this alternative proposal, we again want to emphasize that our fundamental goal is service to the public. The courts have recognized that both nonentertainment programming [206] and entertainment programming [207] can meet public needs. Therefore, if an incumbent broadcaster fulfills his responsibilities, it may be in the public interest to reward that licensee with a significant advantage against any challenger.[207A] Of course, under this alternative, if an incumbent does ask for consideration of its past program service, then—and only then—a challenger should be free to try to demostrate that its proposed service would produce even greater public benefit.[208] In any case, we ask for comments specifically on this point—that is, what role, if any, should consideration of an incumbent's programming practices, and/or a challenger's programming proposals, play in comparative proceedings.

The experimental option

267. Although we originally considered as one possible option an experiment in which the nonentertainment programming and commercial guidelines would be eliminated for one or two license terms in order to determine the effects, we believe several developments may have eliminated any purpose in discussing it as a serious alternative. First, there is a substantial likelihood that the findings we would be seeking from an experiment are already available. We refer to the data showing that the marketplace provides more nonentertainment programming and fewer commercials than our current guildelines. Second, and most importantly, because of the nature of such an experiment—one in which the subjects would have a strong interest in achieving a particular outcome—the results would be subject to considerable question. Finally, if we eliminate our noncommerical and nonentertainment program guidelines, we are prepared to take whatever steps are necessary in the public interest should the marketplace fail. We invite comments on any course of action that might be taken with respect to any experiment.

Conclusion

268. In this Notice we have provided evidence that market forces will, in most instances, yield programming that serves consumer well-being, and that whenever possible the Commission should allow consumer choices rather than regulatory decision-making to be the determinant of the public interest.

269. As noted in the title of this item, we are not merely proposing specific rule and policy changes but are additionally initiating an inquiry into the areas covered by the anticipated changes. Accordingly, we are encouraging robust commentary on our proposals. While comments should be limited to the specific areas noted above, they need not be limited to the specific proposals and alternatives. Alternatives that have not been set forth above may also be proposed. In this regard we specifically solicit comments relating to what method the Commission should use to determine whether or not a market failure has occurred. We take this opportunity to note, however, that arguments supported by facts often carry the greatest weight and thus any relevant empirical data or studies should be either submitted or brought to our attention by appropriate citation.

270. The radio dergulation we are proposing today is part of an overall scheme that has as its hub a shift in our regulatory approach based on structural means of achieving diversity rather than one emphasizing conduct, fraught with all the dangers and inefficiencies inherent in such a system. Such an approach would entail more effective use of multiple ownership regulation, creation of a more representative pool of people making decisions about programs through EEO and minority ownership policies, and increasing the number of outlets through more efficient use of the spectrum, expanding the spectrum available to broadcast radio, and fostering new technologies. It is our belief that such measures will increase the number of independent voices in a fashion most likely to serve the public interest without the need for government intrusion in programming areas.

271. Authority for this proposed rule making and inquiry is contained in Sections 1, 4 (i) and (j), 303 (g) and (r), and 403 of the Communications Act of 1934, as amended (47 U.S.C. 1, 154 (i) and (j), 303 (g) and (r), and 403); Pursuant to applicable procedures set forth in §§ 1.415 and 1.46 of the Commission's rules, interested parties may file comments on or before, January 25, 1980, and reply comments on or before, April 25, 1980. All relevant and timely comments and reply comments will be considered by the Commission before final action is taken in this proceeding. In reaching its determination in this proceeding, the Commission may also take into account other relevant material before it, provided the nature and source of that material are identified in the public docket and made available for public comment.

272. Due to the number of staff personnel involved in this proceeding, we are requesting that those commenting furnish the Commission with an original and 9 copies of all comments, replies, or other documents filed in this proceeding. Participants filing the required copies who also desire that each Commissioner receive a personal copy of the comments may file an additional 6 copies. Members of the general public who wish to express their interest by participating informally in this proceeding may do so by submitting one copy of their comments without regard to form, provided that the Docket Number is specified in the heading. Such informal participants who wish responsible members of the staff to have a personal copy and to have an extra copy available for the Commissioners may file an additional 5 copies.

[205A] Applicants will still be compared on the other criteria discussed in the *Policy Statement on Comparative Broadcast hearings*, 1 FCC 2d 393, 397, 397–98 (1965), including, *inter alia*, diversification, character, and spectrum efficiency. Although the *Policy Statement* purportedly was not intended to cover situations involving renewal applicants, 1 FCC 2d 393, n. 1, the Commission has in fact applied the same criteria to those latter situations. *E.g., Central Florida Enterprises, Inc.* v. *FCC*, No. 76–1742 (D.C. Cir. Sept. 25, 1978), slip op. at 20–21, *reh. denied & clarification granted*, (Jan. 12, 1979), *cert. pet. pending; Citizens Communications Center* v. *FCC*, 447 F.2d 1201, 1212, n. 33 (D.C. Cir. 1971); *Seven League Productions, Inc.*, 1 FCC 2d 1597, 1598 (1965).

[206] *E.g. Office of Communications of United Church of Christ* v. *FCC*, 359 f.2d at 994.

[207] *E.g. Cosmopolitan Broadcasting Corp.* v. *FCC*, 581 F.2d 917, 931 (D.C. Cir. 1978).

[207A] *Central Florida Enterprises, Inc.*, v. *FCC*, *supra*.

[208] As in the past, however, a challenger in this situation would have a very heavy burden in domonstrating that its proposed service would be better then the proven past performance of the incumbent.

Responses will be available for public inspection during regular business hours in the Commission's Dockets Reference Room (Room 239) at its headquarters in Washington, D.C. (1919 M Street, NW.).

For further information on this proceeding, contact Roger Holberg, Broadcast Bureau, (202) 632-6302.

Federal Communications Commission.

William J. Tricarico,

Secretary.

Attachments: Appendices A, B, and C. See attached Statements of Commissioners.

Appendix A—Market Definition

We have used criteria that we believe reflect actual market forces as the basis for our market definitions. Radio stations compete with one another for audience and for advertisers. We have therefore relied on information that suggests these competitive patterns, rather than fixed geographic jurisdictions such as Standard Metropolitan Statistical Areas, to provide the basis for our definitions. In particular, we have relied heavily on the market definitions employed by the Standard Rate & Data Service, Inc. in its monthly *Spot Radio Rates and Data* book. This book is used by advertisers and advertising agencies; stations provide format and rate information and other relevant data. SRDS defines markets and assigns stations to these markets. A station, if it believes that it competes in more than one market, can pay for a duplicate listing in a second market. This suggests that listings represent stations' own perceptions of markets, and we include these duplicate listings in our market definition.

SRDS defines markets based on its own judgment, supplemented by direct station input. Markets are defined more broadly than city of license. For example, the SRDS Washington, D.C., market includes Alexandria, Arlington, Fairfax, Falls Church, and Woodbridge, Va., and Bethesda, Bladensburg, Potomac-Cabin John, Rockville, Silver Spring, and Wheaton, Md.

Although SRDS market definitions often conform to SMSA's, they do not always. For example, the SMSA for Duluth-Superior includes all of St. Louis county in Minnesota, which extends approximately 100 miles north of Duluth. The SRDS market does not include radio stations in northern St. Louis county, for example the station in Ely, 75 miles north of Duluth.

In general, we have adhered to SRDS definitions. There are six exceptions. SRDS lists the Dallas and Fort Worth markets separately. Approximately half of the Fort Worth stations, however, pay for duplicate listings under Dallas. Therefore we have combined the two. For five major metropolitan areas—Los Angeles, Chicago, New York, Detroit, and Philadelphia—SRDS provides both a city listing and a broader "urban area" listing. We believe that the city market definition is too narrow but, in several cases, the urban area designation is too broad. For example, the New York urban area includes stations in eastern Suffolk county that are about 100 miles from Manhattan. For these six metropolitan areas we made our own judgments about appropriate market designations.

In our station count within markets, we excluded FM stations that duplicated AM station programming more than 50% of the time. Since SRDS data is limited to commercial stations, we relied on the Broadcasting *Yearbook 1979* and the Carnegie Commission study for data on noncommercial stations.

We seek comment on the market definitions we have employed including any alternate proposals concerning market definition.

Appendix B

PART 0—COMMISSION ORGANIZATION

1. Section 0.281 would be amended by revising (a) (7), (8), (9) and (10) to read as follows:

§ 0.281 Authority delegated.

* * * * *

(a) *Applications.* * * *

(7) *Programming: Commercial matter.* Commercial TV proposals exceeding 16 minutes of commercial matter per hour, or, during periods of high demand for political advertising, providing for exceptions permitting in excess of 20 minutes of commercial matter per hour during 10 percent or more of the station's total weekly hours of operation.

(8) *Programming: Program content and ascertainment of community needs.* (i) Commercial TV proposals (except those made by UHF stations not affiliated with major networks) which project for the hours 6:00 a.m. to 12:00 midnight less than the indicated percentages in one or more of the following categories: Five percent total local programming, five percent information (news plus public affairs) programming, ten percent total non-entertainment programming.

(ii) Commercial TV proposals containing substantial ascertainment defects which, for any reason, cannot be resolved by further staff inquiry or action.

(9) *Programming: Substantial shifts in format.* Commercial TV applications disclosing substantial changes affecting either the entertainment or non-entertainment portions of existing formats which raise significant public interest questions, or which are opposed by the viewing public.

(10) *Programming: Promise versus performance.* Commercial TV renewal, transfer, and assignment applications which vary substantially from prior representations with respect to commercial practices or the programming categories set forth at § 0.281(a)(8)(i), and for which variation there is lacking, in the judgment of the Broadcast Bureau, adequate justification in the public interest.

* * * * *

PART 73—RADIO BROADCAST SERVICES

2. Section 73.3526 would be amended by revising the introductory text of (a), (a)(1), (10), (11), (12), the closing text of (a) and note 2 to read as follows:

§ 73.3526 Local public inspection file of commercial stations.

(a) *Records to be maintained.* Every applicant for a construction permit for a new station in the commercial broadcast services shall maintain for public inspection a file containing the material described in subparagraph (1) of this paragraph. Every permittee or licensee of an AM, FM or TV station in the commercial broadcast services shall maintain for public inspection a file for such station containing the material described in subparagraphs (1), (2), (3), (4), (5), (6), and (7) of this paragraph. In addition, every permittee or licensee of a TV station shall maintain for public inspection a file for such station containing the material described in subparagraph (8), (9), (11) and (12) of this paragraph. The material to be contained in the file is as follows:

(1) A copy of every application tendered for filing, with respect to which local public notice is required to be given under the provisions of § 73.3580 or § 73.3594; and all exhibits, letters and other documents tendered for filing as part thereof; all amendments thereto, copies of all documents incorporated therein by reference, all correspondence between the FCC and the applicant pertaining to the application after it has been tendered for filing, and copies of Initial Decisions and Final Decisions in hearing cases pertaining thereto, which according to the provisions of §§ 0.451–0.461 of the rules are open for public inspection at the offices of the FCC. Information incorporated by reference which is already in the local file need not be duplicated if the entry making the reference sufficiently identifies the information so that it may be found in the file, and if there has been no change in the document since the date of filing and the applicant, after making the reference, so states. If petitions to deny are filed against the application, and have been duly served on the applicant, a statement that such a petition has been filed shall appear in the local file together with the name and address of the party filing the petition. The file shall also contain a copy of every writen citizen agreement. For purposes of this

section, a citizen agreement is a written agreement between a broadcast applicant, permittee, or licensee, and one or more citizens or citizen groups entered for primarily noncommercial purposes. This definition includes those agreements that deal with goals or proposed practices directly or indirectly affecting station operation in the public interest, in areas such as—but not limited to—community ascertainment (where such ascertainment is required by the rules), programming, and employment. It excludes common commercial agreements such as advertising contracts; union, employment, and personal services contracts; network affiliation and syndication, program supply contracts. However, the mere inclusion of commercial terms in a primarily noncommercial agreement—such as a provision for payment of fees for future services of the citizen parties (see "Report and Order," Docket 19518, 57 FCC 2d 494 (1976)—would not cause the agreement to be considered commercial for purposes of this Section.

* * * * *

(10) Although not part of the regular file for public inspection, program logs for TV and non-commercial radio stations, and any record of programs or commercials aired kept by commercial radio stations, will be available for public inspection under the circumstances set forth in § 73.1850 and discussed in the Public Broadcasting Procedural Manual; Revised Edition.

(11) Each licensee or permittee of a commerically operated TV station (except as provided in Note 2, below) shall place in the station's public inspection file appropriate documentation relating to its efforts to interview a representative cross-section of community leaders within its service area to ascertain community problems and needs. Such documentation shall be placed in the station's public inspection file within a reasonable time after the date of completion of each interview but in no event later than the due date for filing the station's application for renewal of license and shall include:

(i) The name, address, organization, and position or title of the community leader interviewed;

(ii) The date, time and place of the interview;

(iii) The name of the principal, management-level or other employee of the station conducting the interview;

(iv) The problems and needs discussed during the interview or, when the interviewee requests that his/her statements be held in confidence, that request shall be noted; and

(v) For interviews conducted by non-principals or non-managers, the date of review of the interview record by a principal or management-level employee of the station.

Additionally, upon the filing of the application for renewal of license each such licensee shall forward to the FCC as part of the application for renewal of license a checklist indicating the numbers of community leaders interviewed during the current license term representing the several elements found on the form: *Provided,* That, if a community lacks one of the enumerated instititions or elements, the licensee or permittee should so indicate by providing a brief explanation on its checklist.

(12) Each licensee or permittee of a commerically operated TV station (except as provided in Note 2, below) shall place in the station's public inspection file documentation relating to its efforts to consult with a roughly random sample of members of the general public within its city of license to ascertain community problems and needs. Such documentation shall consist of:

(i) Information relating to the total population for the station's city of license including the numbers and proportions of males and females; of minorities; of youth (17 and under); and of the elderly (65 and over);

(ii) A narative statement of the sources consulted and the methods followed in conducting the general public survey, including the number of people surveyed and the results thereof.

Such documentation shall be placed in the public inspection file within a reasonable time after completion of the survey but in no event later than the date the station's application for renewal of license is filed. Upon filing its application for renewal of license, each such licensee or permittee must certify that the above-noted documentation has been placed in the station's public inspection file.

* * * * *

Note 2. Paragraphs (a)(11) and (a)(12) of this section shall not apply to commerical TV stations within cities of license which (1) have a population, according to the immediately proceding decennial U.S. Census, of 10,000 persons or less; and (2) are located outside all Standard Metropolitan Statistical Areas (SMSA's), as defined by the Federal Bureau of the Census.

* * * * *

3. Section 73.1800 would be amended by revising paragraph (a) to read as follows:

§ 73.1800 General requirements relating to logs.

(a) The licensee of each television station shall maintain a program log as set forth in § 73.1810. The licensee of each AM, FM and TV station, shall maintain operating and maintenance logs as set forth in §§ 73.1820 and 73.1830. Each log required to be kept shall be kept by the station employee or employees (or contract operator) competent to do so, having actual knowledge of the facts required. The person keeping the log must make entries that accurately reflect the operating of the station. In the case of program and operating logs, the employee shall sign the appropriate log when starting duty and again when going off duty and setting forth the time of each. In the case of maintenance logs, the employee shall sign the log upon completion of the required maintenance and inspection entries. When the employee keeping a program or operating log signs it upon going off duty or completing maintenance log entries, that person attests to the fact that the log, with any corrections or additions made before it was signed, is an accurate representation of what transpired.

* * * * *

4. Section 73.1810 (a) and (b)(5) would be revised and undesignated headnote immediately following paragraph (h)(3) would be changed as follows:

§ 73.1810 Program Logs.

Commerical TV Stations

(a) Commerical TV stations shall keep a program log in accordance with the provisions of § 73.1800 for each broadcast day which, in this context, means from the station's sign-on to its sign-off.

(b) Entries. The following entries shall be made in the program log:

* * * * *

(5) For Emergency Broadcast System Operations. An entry for tests of the EBS procedures pursuant to the requirements of Subpart G of this part and the appropriate station EBS checklist, unless such entries are consistently made in the station operating log. All commerical AM and FM stations shall make such entries in their operating log.

* * * * *

(h) * * *

(3) * * *

All TV Stations and Noncommerical Educational AM and FM Stations

* * * * *

6. Section 73.1820 would be amended by revising paragraph (a)(1)(iv) to read as follows:

§ 73.1820 Operating Logs.

* * * * *

(a) * * *

(1) * * *

(iv) An entry of each test of the Emergency Broadcast System procedures pursuant to the requirements of Subpart G of this part and the appropriate station EBS checklist, unless such entries are consistently made in the station program log. All commerical AM and FM radio stations shall make such entries in their operating logs. TV stations may make entries in the program log.

* * * * *

7. Section 73.1850 would be amended by revising paragraph (a) to read as follows:

§ 73.1850 Public inspection of program logs.

(a) All stations required to keep program logs, and all stations not required to keep program logs but which keep a record of programs and/or commericals broadcast notwithstanding the lack of a requirement to do so, shall make their program logs or records available for public inspection and reproduction at a location convenient and accessible to the residents of the community to which the station is licensed. All such requests for inspection shall be subject to the procedural requirements in paragraph (b) of this section. Where good cause exists, the licensee may refuse to permit such inspection. (See paragraph 64, the Public and Broadcasting Procedural Manual). The licensee shall remain responsible for the safekeeping of the logs or records when permitting inspections.

* * * * *

STATISTICAL TABLES

Table 1

Number of AM and FM Radio Stations on the Air, 1934-1979

YEAR-(as of 1/1)	AM	FM	TOTAL
1934	583	–	583
1935	585	–	585
1936	616	–	616
1937	646	–	646
1938	689	–	689
1939	722	–	722
1940	765	–	765
1941	831	20	851
1942	887	43	930
1943	910	49	959
1944	910	52	962
1945	919	54	973
1946	948	57	1,005
1947	1,062	150	1,212
1948	1,621	473	2,094
1949	2,006	771	2,777
1950	2,144	753	2,897
1951	2,281	732	3,013
1952	2,355	721	3,076
1953	2,458	686	3,144
1954	2,583	670	3,253
1955	2,732	664	3,396
1956	2,896	656	3,552
1957	3,079	665	3,744
1958	3,253	695	3,948
1959	3,377	776	4,153
1960	3,483	906	4,389
1961	3,602	1,075	4,677
1962	3,745	1,213	4,958
1963	3,860	1,341	5,201
1964	3,976	1,424	5,400
1965	4,025	1,605	5,630
1966	4,075	1,806	5,881
1967	4,135	1,926	6,061
2968	4,203	2,198	6,401
1969	4,254	2,393	6,647
1970	4,288	2,542	6,830
1971	4,343	2,661	7,004
1972	4,367	2,873	7,240
1973	4,392	3,046	7,438
1974	4,409	3,231	7,640
1975	4,448	3,455	7,903
1976	4,479	3,665	8,144
1977	4,497	3,743	8,240
1978	4,513	3,927	8,440
1979	4,547	4,074	8,621
1979 (7/31)	4,547	4,107	8,654

Sources: 1934-1948 data are from Christopher H. Sterling and Timothy R. Haight, The Mass Media: Aspen Institute Guide to Communication Industry Trends (Praeger Publishers, New York, 1978), Table 170-A, p. 43; 1949-1976 data are from the FCC Annual Report for Fiscal Year 1976; 1977-1979 data are from F.C.C. Broadcast Bureau, License Division, AM-FM Branch.

Table 2: The Number of Stations in Selected Radio Markets, 1934-1979

Market	Current # Stations	# of Stations as of 1974	1969	1959	1949	1939	1934
Pittsburgh, Pennsylvania	35	35	31	22	19	6	6
Cincinnati, Ohio	25	23	21	13	8	5	5
Birmingham, Alabama	20	18	17	13	10	3	3
Greensboro, N.C.	17	15	13	9	6	2	1
Las Vegas, Nevada	13	13	11	6	3	0	0
Austin, Texas	13	12	11	7	4	2	1
Roanoke, Virginia	12	12	10	7	5	1	1
Lincoln, Nebraska	11	10	8	4	3	1	1
Sarasota, Florida	10	10	9	4	3	1	0
Canton, Ohio	9	9	9	6	4	1	1
Eau Claire, Wisc.	8	7	7	5	4	1	0
Erie, Pennsylvania	8	8	6	5	4	1	0
Tyler, Texas	7	6	6	4	2	1	1
Wichita Falls, Texas	6	5	5	3	3	1	0
Gastonia, North Carolina	5	5	5	4	3	1	0
Bay City, Michigan	4	4	4	2	1	1	1

Notes & Sources:

(1) These markets were chosen by a method that assured an even distribution of market sizes, but within any market size the particular market included was randomly selected. Markets were ranked according to number of stations (See Table 3), and then a starting point was chosen (a number between one and 15 was picked, at random). From that starting point, every fifteenth market (in descending order of ranking) was chosen. Where several stations held equal rank (for example,more than one market had 17 stations) the particular market chosen was picked at random (by using a random number generator).

(2) The market rankings and station assignments to markets come from Table 3 and Appendix A.

(3) The years that stations began operation, which underlie this table, come from Standard Rate & Data Service, Inc., Spot Radio Rates and Data, Vol. 61, No. 3, March 1, 1979, Skokie, Illinois, Broadcasting Yearbook 1979, and F.C.C. license records.

Table 3: Commercial and Noncommercial Radio Stations in Large Markets, 1979

Total # Stations	Market	Commercial # AM	Stations # FM	Noncommercial # NPR	Stations #Other
64	Los Angeles	29	28	4	3
59	Chicago	22	24	1	12
54	New York	23	22	3	6
42	San Francisco	18	16	3	5
40	Boston	16	15	2	7
37	Dallas-Fort Worth	16	15	1	5
36	St. Louis	14	11	1	10
36	Seattle	19	12	1	4
36	Washington, D.C.	18	13	2	3
35	Detroit	15	18	1	1
35	Pittsburgh	18	12	2	3
34	Philadelphia	15	14	1	4
31	Atlanta	18	8	1	4
31	Houston	14	12	1	4
31	Miami-Miami Beach	13	14	1	3
30	Norfolk-Portsmouth-Newport News-Hampton	14	11	1	4
30	Minneapolis-St. Paul	15	7	3	5
29	Tampa-St. Petersburg	18	9	1	1
28	Cleveland	11	13	1	3
28	Phoenix	19	8	1	0
28	Portland	15	10	3	0
28	San Diego	13	12	1	2
28	Denver	17	10	1	0
27	Baltimore	13	10	2	2
25	Cincinnati	11	8	1	5
25	Kansas City	11	10	1	3
24	Hartford-New Britain	9	10	0	5
24	Milwaukee	10	11	1	2
24	San Antonio	13	9	0	2
23	Honolulu	17	5	0	1
23	Jacksonville	14	7	1	1
22	Albany-Schenectady-Troy	9	8	2	3
22	Louisville	11	7	3	1
22	Memphis	10	7	1	4
22	New Orleans	11	8	1	2
22	Oklahoma City	9	12	0	1
22	Orlando	9	9	0	4
21	Fresno	12	7	1	1
21	Indianapolis	8	6	1	6
21	Riverside-San Bernardino-Ontario	9	8	1	3
21	Albuquerque	12	6	0	3
20	Birmingham, Ala.	11	7	1	1
20	Buffalo	8	9	3	0

Table 3, continued

20	Raleigh-Durham	10	6	0	4
20	Salt Lake City	14	6	0	0
20	Spokane	10	6	0	4
19	San Juan	12	6	1	0
19	Nashville	10	6	1	2
19	Sacramento	9	9	0	1
19	Scranton	10	5	1	3
18	Richmond, Va.	11	5	1	1
18	Columbus, Ohio	7	6	3	2
18	Springfield-Chicopee-Holyoke	9	3	0	6
18	Syracuse	8	8	1	1
17	Colorado Springs	8	7	0	2
17	Portland, Maine	6	10	1	0
17	Greensboro, N.C.	8	5	0	4
17	Tucson	10	5	2	0
17	West Palm Beach	9	6	1	1
17	El Paso	10	6	1	0
16	Chattanooga	8	6	0	2
16	Columbia, S.C.	6	6	1	3
16	Rochester, N.Y.	6	7	1	2
15	Allentown, Pa.	7	5	0	3
15	Eugene,Oregon	7	5	2	1
15	Tulsa	7	7	1	0
15	Grand Rapids, Mi.	7	6	1	1
15	Knoxville	9	4	1	1
15	Little Rock	9	5	0	1
15	Omaha	7	6	1	1
15	San Jose	5	7	0	3
14	Beaumont	7	6	1	0
14	Charleston, W. Va.	7	6	0	1
14	Davenport-Rock Island	5	6	0	3
14	Greenville-Spartanburg, S.C.	10	3	1	0
14	Huntington-Ashland-Ironton	8	4	0	2
14	Jackson	7	6	0	1
14	Lubbock	7	5	0	2
14	Madison	4	6	2	2
14	Mobile	8	5	0	1
14	Providence	10	3	0	1
14	Savannah	7	6	0	1
14	Shreveport	7	6	0	1
13	Austin	5	6	1	1
13	Sioux Falls, S.D.	5	4	0	4
13	Akron	5	4	1	3
13	Augusta, Ga.	8	4	0	1
13	Charlotte, N.C.	8	4	0	1
13	Dayton	4	4	0	5
13	Ft. Lauderdale-Hollywood	7	5	0	1
13	Las Vegas	8	4	0	1
13	Modesto	6	5	0	2
13	Utica-Rome, N.Y.	7	5	0	1
13	Appleton	7	4	0	2
12	Wichita	5	5	1	1

Table 3, continued

12	Charleston, S.C.	6	5	1	0
12	Des Moines	6	5	0	1
12	Duluth-Superior	6	3	1	2
12	Peoria	6	5	1	0
12	Reno	6	5	0	1
12	Roanoke	7	4	1	0
12	Santa Barbara	6	5	0	1
12	Toledo	5	5	1	1
12	Youngstown	7	4	1	0
12	Amarillo	6	5	0	1
12	Champaign-Urbana	3	6	2	1
11	Bakersfield	7	4	0	0
11	Baton Rouge	7	4	0	0
11	Boise City	7	3	0	1
11	Corpus Christi	7	4	0	0
11	Ft. Wayne	5	4	0	2
11	Harrisburg	5	3	0	3
11	Lansing	5	4	2	0
11	Lincoln	5	4	0	2
11	Montgomery	7	4	0	0
11	Odessa, Tx.	5	5	0	1
11	Oxnard-Ventura	5	6	0	0
11	Parkersburg, W.Va	6	3	0	2
11	Pueblo	7	3	0	1
11	Springfield, Mo.	6	4	1	0
11	Takoma	5	3	1	2
11	Tallahassee	4	5	1	1
11	Winston-Salem	6	4	1	0
10	Columbus, Ga.	6	4	0	0
10	Evansville, Ind.	4	4	0	2
10	Fargo-Moorhead, N.D.	4	3	1	2
10	Anchorage	6	3	1	0
10	Atlantic City	5	5	0	0
10	Billings	5	3	0	2
10	Cedar Rapids, Ia.	4	3	1	2
10	Florence-Sheffield, Ala.	6	4	0	0
10	Huntsville	5	4	1	0
10	Kalamazoo	5	3	1	1
10	Sarasota-Bradenton	6	3	0	1
10	Terre Haute	4	5	0	1
10	Waterloo-Cedar Falls, Ia.	4	2	2	2
10	Ann Arbor	5	2	2	1
9	Binghampton, N.Y.	4	3	1	1
9	Canton	6	3	0	0
9	Fayetteville, N.C.	6	2	0	1
9	Flint	6	2	1	0
9	Ft. Myers, Fl.	3	5	0	1
9	Lancaster, Pa.	4	4	0	1
9	Lexington, Ky.	5	3	1	0
9	Macon, Ga.	6	3	0	0
9	Manchester, N.H.	5	3	0	1
9	McAllen-Pharr, Tex.	4	4	0	1

Table 3, continued

9	Monroe, La.	4	4	0	1
9	Pensacola, Fl.	6	2	0	1
9	South Bend, Ind.	4	4	0	1
9	Wheeling, W.Va.	4	3	0	2
9	Wilmington, N.C.	4	4	0	1
9	Yakima, Wash.	4	4	0	1
8	Ft. Smith, Ark.	5	3	0	0
8	Hamilton-Middletown	4	3	0	1
8	Biloxi-Gulfport, Miss.	5	3	0	0
8	Bridgeport, Ct.	4	3	0	1
8	Worcester, Mass.	5	1	0	2
8	Topeka	6	2	0	0
8	Columbia, Mo.	2	2	1	3
8	Daytona Beach	5	3	0	0
8	Eau Claire	5	2	0	1
8	Elmira	4	3	0	1
8	Green Bay	3	2	1	2
8	La Crosse, Wi.	3	3	2	0
8	Lynchburg, Va.	5	3	0	0
8	New Haven	4	3	0	1
8	Ponce, P.R.	4	3	0	1
8	Rochester, Mn.	3	4	0	1
8	Rockford, Ill.	5	3	0	0
8	Salinas, Ca.	3	4	0	1
8	Sioux City	4	2	1	1

Sources: Standard Rate & Data Service, Inc., Spot Radio Rates & Data, Vol. 61, No. 3, March 1, 1979; Broadcasting Yearbook 1979; and A Public Trust, The Report of the Carnegie Commission on the Future of Public Broadcasting, Bantom Books Inc., New York, 1979.

For explanation of market definition, see Appendix A.

Table 4: Commercial Radio Stations Reporting Some Regularly Scheduled Black Programming, 1979

Number of Stations in a Given Market Reporting Some Regularly Scheduled Black Programming 1/	Number of Markets	Total Number of Stations Reporting Full Time Black Programming	Total Number of Stations Reporting Some Black Programming. 2/
9	1	5	4
8	1	3	5
7	2	8	6
6	2	7	5
5	6	22	8
4	12	23	25
3	20	16	44
2	39	23	55
1	157	29	128
	239	136	280

Source:

Standard Rate and Data Service, Inc., Spot Radio Rates and Data, Vol. 61, No. 3, March 1, 1979, "Radio Stations Regularly Scheduling Negro/black Programs," p.19. Methods and Sources used by SRDS: Employing a rotation system, questionnaires are mailed frequently to insure data reported is current and accurate. Definition as to what constitutes Negro/black Programming is left to the discretion of the stations. Each station is advised that failure to return a completed form will mean deletion of the station from this tabulation as information is not carried forward. Stations not maintaining full monthly listings are not reported since it is not possible to maintain current information.

1/ Market definitions from Table 3 and Appendix A.

2/ The 280 stations reporting part-time Black programming averaged 19.8 hours per week of Black programming.

Table 5: Radio Markets with Regularly Scheduled Black Oriented Programming on Commercial Stations, 1979, by Market Size

Total # stations in the market 1/	# of markets of that size	# of markets with at least one commercial station with full time black programming 2/	# of markets with at least one commercial station with some black programming 2/
more than 31	12	11	11
23-31	19	14	17
16-22	31	15	24
10-15	74	20	42
8-9	36	7	19

1/ Includes both commercial and noncommercial stations. Data from Table 3 and SRDS.

2/ Source: Standard Rate & Data Service, Inc., Spot Radio Rates and Data, Vol. 61, No. 3, March 1, 1979, "Radio Stations Regularly Scheduling Negro/black Programs," p.19. For methods and sources used by SRDS, see Table 4.

Table 6: Commercial Radio Stations Reporting Some Regularly Scheduled Spanish Language Programming, 1979.

Number of Stations in a Given Market Reporting Some Regularly Scheduled Spanish Language Programming. 1/	Number of Markets	Total Number of Stations Reporting Some Spanish Language Programming But No Other Foreign Language Programming. 2/	Total Number of Stations Reporting Some Spanish Language Programming and Also Other Foreign Language Programming 3/	Total Number of Stations Reporting Full-Time Spanish Language Programming
6	2	4	5	3
5	5	5	10	10
4	3	6	9	3
3	13	17	6	16
2	32	40	16	8
1	118	87	27	4
Totals	173	153	73	44

Source: Standard Rate and Data Service, Inc., Spot Radio Rates and Data, Vol. 61, No. 3, March 1, 1979, "Radio Stations Regularly Scheduling Foreign Language Programs," pp. 22-23. Methods and Sources used by SRDS: Employing a rotation system SRDS mails questionnaires frequently to insure data reported is current and accurate. Definition as to what constitutes Foreign Language Programming is left to the discretion of the stations. Each station is advised that failure to return a completed form will mean deletion of the station from this tabulation as information from previous reports is not carried forward. Stations not maintaining full monthly listings are unreported since it is not possible to maintain current information.

1/ Market definitions from Table 3 and Appendix A.

2/ The 153 stations reporting part-time Spanish language programming, but not reporting any other foreign language programming, average 14.9 hours per week of Spanish language programming.

3/ For example, Spanish and Italian. The hours of foreign language programming provided was not broken down by language.

Table 7: Commercial Radio Stations Reporting Some Regularly Scheduled Foreign Language Programming Other Than Spanish, 1979.

Language	Total # of Markets with Some Regularly Scheduled Programming in That Language 1/	Number of Stations Programming in That Language: Total # of Stations with Some Regularly Scheduled Programming in That Language	Total # of Stations with Some Regularly Scheduled Programming in That Language Only	Total # of Stations with Some Regularly Scheduled Programming in That Language and Other Language
Arabic	3	3	0	3
Assyrian	2	2	0	2
Basque	3	3	2	1
Bohemian	1	1	0	1
British	1	1	0	1
Bulgarian	1	1	0	1
Cajun	3	3	0	3
Chinese	1	1	0	1
Chomorro	1	1	0	1
Croatian	5	7	2	5
Czech	5	7	0	7
Dutch	1	2	0	2

Source: Standard Rate and Data Service, Inc., Spot Radio Rates and Data, Vol. 61, #3, March 1, 1979. "Radio Stations Regularly Scheduling Foreign Language Programs," pp. 22-23. For methods and sources used, see Table 6.

1/ Market definitions from Table 3 and SRDS.

Table 7, continued

Language	Markets	Scheduled Programming in that Language	Scheduled Programming in that Language Only	Scheduled Programming in That & Other Language
Estonian	1	1	0	1
Filipino	4	4	2	2
Finnish	3	4	3	1
French	25	27	15	12
German	39	43	13	30
Greek	24	27	4	23
Haitian	1	0	1	1
Hebrew	1	1	0	1
Hindi	1	1	0	1
Hindustani	1	1	0	1
Hungarian	9	12	2	10
Indian (Amer.)	2	2	0	2
Indian Navajo	2	2	0	2
(West)	8	9	2	7
Indian	1	1	0	1
Indonesian	1	1	0	1
Irish	5	6	0	6
Italian	40	55	7	48
Japanese	5	5	0	5
Korean	4	4	1	3
Latin	1	0	0	1
Latvian	1	1	0	1
Lebanese	1	1	1	0
Lithuanian	6	6	0	6
Macedonian	2	2	0	2
Maltese	1	1	0	1
Norwegian	1	1	0	1
Pakistani	1	1	0	1
Persian	1	1	0	1
Polish	53	63	13	50
Portugese	23	29	5	24
Punjabi	1	1	0	1
Rumanian	5	5	0	5
Russian	3	3	0	3

Table 7, continued

Language	Markets	Scheduled Programming in That Language	Scheduled Programming In That Language Only	Scheduled Programming In That & Other Language
Samoan	2	2	1	1
Scandinavian	2	2	0	2
Serbian	3	4	0	4
Sioux	1	1	1	0
Slavic	2	2	0	2
Slovak	5	7	0	7
Slovenian	1	2	0	2
Swahili	1	1	0	1
Swedish	5	6	1	5
Swiss	1	1	0	1
Syrian	1	1	0	1
Tagalog	2	2	0	2
Ukrainian	7	7	0	7
Vietnamese	1	1	0	1
Yiddish	5	6	1	5
Yugoslavia	4	4	1	3

Table 8: Radio Stations Providing Ethnic or Foreign Language Programming, SRDS vs. Broadcasting Yearbook Data

Type of Programming	Number of stations providing programming according to SRDS	Number of stations providing programming according to Broadcasting Yearbook
American Indian	12	55
Black	416	793
French	27	105
German	43	121
Greek	27	58
Italian	55	120
Japanese	5	II
Polish	63	183
Portuguese	29	33
Spanish	270	570
Ukranian	7	14

Sources: Standard Rate and Data Services, Inc., Spot Radio Rates and Data, Vol. 61, No. 3, March 1, 1979, pp. 19, 22-23. For methods and sources used by SRDS, see Tables 4 and 6.

: Broadcasting Yearbook, 1979, pp. D-74 - D-104, "Formats" and "Special Programming." A station using a combination of formats may appear under several classifications. Blocks of programming averaging less than 20 hours per week are considered "special programming."

Table 9

LISTENER ATTITUDES TOWARD RADIO NEWS */

	Total Mention
News on the radio is important – I especially tune to a particular station to hear the news.	30.0%
When news comes on the radio, I pay attention to the news content.	56.4%
Radio news doesn't matter much to me – I pay little attention to the news or news content.	10.1%
I dislike it when the news comes on the radio. I usually turn off the radio or switch stations when news comes on.	3.2%
No answer.	3.0%
Approximate Totals	**

Sample size = 1100.

SOURCE: AP Research, "Radio News Listening Attitudes," (Magid Study), p.11 B.

*/ From responses to the question: "RADIO STATIONS OFFER ALL TYPES OF DIFFERENT ENTERTAINMENT AND INFORMATION. LET'S TALK ABOUT RADIO NEWS FOR A MOMENT. WHICH OF THESE STATEMENTS BEST DESCRIBES YOUR ATTITUDE TOWARD NEWS ON THE RADIO?"

**/. Multiple mentions need not total 100%.

Table 10A: Percentage of Stations in Market with Various Amounts of News and Public Affairs Programming, by Market Size

Number of Stations in the Market	Number of Markets	Number of Stations in Sample	Percentage of Stations with Given Amount of News and Public Affairs Programming. 0-4%	4-6%	6-8%	8-10%	10-25%	25-50%	over 50%
more than 31	12	383	3.8	15.8	20.0	19.2	33.4	4.1	3.8
23-31	19	400	4.7	21.3	20.4	11.9	34.6	2.8	4.4
16-22	32	468	4.9	13.3	17.6	13.9	44.4	3.4	2.5
10-15	74	724	2.7	12.1	15.8	17.1	49.0	2.3	1.0
8-9	36	243	2.9	9.6	8.9	14.1	62.0	2.1	0.3
3-7	88	272	1.0	2.6	6.9	11.2	76.9	1.4	0.0
1-2	197	260	0.3	0.5	5.1	8.9	78.7	6.4	0.0

SOURCE: License Renewal Applications.

NOTE: In each market class, each market was given equal weight, rather than each station.

Table 10B: Percentage of Stations in Market with Various Amounts of News and Public Affairs Programming, by Market Size

Number of Stations in the Market	Number of Markets	Number of Stations in Sample	Percentage of Stations with Given Amount of News and Public Affairs Programming. 0-4%	4-6%	6-8%	8-10%	10-25%	25-50%	over 50%
more than 31	12	383	4.2	16.2	19.3	18.8	33.4	4.2	3.9
23-31	19	400	4.5	21.3	20.3	12.3	34.3	3.0	4.5
16-22	32	468	4.9	13.9	17.7	14.7	42.7	3.6	2.4
10-15	74	724	2.7	12.4	16.0	16.9	47.2	3.9	0.8
8-9	36	243	3.7	8.2	10.3	14.0	61.7	1.6	0.4
3-7	88	272	1.1	2.9	7.4	8.8	79.0	0.7	0.0
1-2	197	260	0.0	1.2	4.2	8.8	79.2	6.5	0.0

SOURCE: License Renewal Applications.

NOTE: In each market class, each station was given equal weight, rather than each market.

Table 11A: Percentage of Stations in Market with Various Amounts of News Programming, by Market Size

Number of Stations in the Market	Number of Markets	Number of Stations in Sample	Percentage of Stations with Given Amount of News Programming						
			0-4%	4-6%	6-8%	8-10%	10-25%	25-50%	over 50%
more than 31	12	383	20.1	26.8	23.1	10.5	15.3	0.9	3.4
23-31	19	400	19.9	29.9	13.7	13.3	18.7	1.4	3.0
16-22	32	468	13.5	20.8	21.3	15.1	25.6	2.1	1.6
10-15	74	724	10.0	18.6	19.3	19.2	31.7	0.9	0.5
8-9	36	243	5.9	15.0	13.0	18.8	45.9	1.1	0.3
3-7	88	272	1.5	5.3	11.2	16.3	65.7	0.0	0.0
1-2	197	260	0.5	4.3	9.1	14.0	72.0	0.0	0.0

SOURCE: License Renewal Applications.

NOTE: In each market class, each market was given equal weight, rather than each station.

Table 11B: Percentage of Stations in Market with Various Amounts of News Programming, by Market Size

Number of Stations in the Market	Number of Markets	Number of Stations in Sample	Percentage of Stations with Given Amount of News Programming						
			0-4%	4-6%	6-8%	8-10%	10-25%	25-50%	over 50%
more than 31	12	383	20.6	26.9	22.7	9.9	15.1	1.6	3.1
23-31	19	400	19.8	29.8	14.3	13.3	18.5	1.5	3.0
16-22	32	468	13.7	21.4	21.6	14.1	24.6	3.2	1.5
10-15	74	724	10.1	18.8	20.0	18.8	31.1	0.7	0.6
8-9	36	243	6.2	15.6	13.6	18.1	44.4	1.6	0.4
3-7	88	272	1.8	5.9	10.3	15.8	66.2	0.0	0.0
1-2	197	260	0.4	4.6	8.5	13.5	72.7	0.4	0.0

SOURCE: License Renewal Applications.

NOTE: In each market class, each station was given equal weight, rather than each market.

Table 12A: Percentage of Stations in Market with Various Amounts of Public Affairs Programming, by Market Size

Number of Stations in the Market	Number of Markets	Number of Stations	Percentage of Stations with Given Amount of Public Affairs Programming: 0-2%	2-4%	4-6%	over 6%
more than 31	12	383	37.4	35.8	12.1	14.7
23-31	19	400	46.9	33.8	8.1	11.3
16-22	32	468	50.2	31.6	8.9	9.3
10-15	74	724	52.7	32.2	9.3	5.8
8- 9	36	243	43.1	42.9	8.9	5.1
3- 7	88	272	54.1	34.7	9.8	1.3
1- 2	197	260	43.9	35.7	10.9	9.6

SOURCE: License Renewal Applications.

NOTE: In each market class, each market was given equal weight, rather than each station.

Table 12B: Percentage of Stations in Market with Various Amounts of Public Affairs Programming, by Market Size

Number of Stations in the Market	Number of Markets	Number of Stations in Sample	Percentage of Stations with Given Amount of Public Affairs Programming			
			0-2%	2-4%	4-6%	over 6%
more than 31	12	383	37.1	35.5	13.1	14.4
23-31	19	400	46.3	34.5	8.3	11.1
16-22	32	468	51.1	31.0	8.8	9.2
10-15	74	724	53.5	32.0	8.6	5.9
8-9	36	243	43.6	42.4	9.1	4.9
3-7	88	272	49.6	38.2	11.4	0.7
1-2	197	260	40.8	35.8	13.5	10.0

SOURCE: License Renewal Applications.

NOTE: In each market class, each station was given equal weight, rather than each market.

Table 13
Number of Commercial and Noncommercial Radio Stations Doing Substantial Amounts of News and Public Affairs, 1979

Total # of Stations in Market	Market	Number of Stations with over 50% News and Public Affairs	Number of Stations with 25-50% News and Public Affairs	Number of NPR Stations	Number of All News Stations According to Broadcasting Yearbook
64	Los Angeles	2	1	4	2
59	Chicago	1	1	1	2
54	New York	3	5	3	3
42	San Francisco	3	0	3	2
40	Boston	1	2	2	1
37	Dallas-Fort Worth	1	1	1	3
36	St. Louis	0	1	1	1
36	Seattle	0	1	1	0
36	Washington, D.C.	1	0	2	2
35	Detroit	0	1	1	1
35	Pittsburgh	1	3	2	1
34	Philadelphia	2	0	1	2
31	Atlanta	2	0	1	2
31	Houston	2	2	1	3
31	Miami-Miami Beach	4	1	1	1
30	Norfolk-Portsmouth Newport News-Hampton	0	0	1	0

Table 13, continued

30	Minneapolis-St. Paul	1	0	3	2
29	Tampa-St. Petersburg	1	1	1	1
28	Cleveland	1	0	1	1
28	Phoenix	1	1	1	1
28	Portland	2	0	3	1
28	San Diego	0	1	1	2
28	Denver	2	1	1	1
27	Baltimore	0	0	2	0
25	Cincinnati	0	0	1	0
25	Kansas City	1	1	1	0
24	Hartford-New Britain	1	1	0	1
24	Milwaukee	0	0	1	1
24	San Antonio	0	0	0	1
23	Honolulu	1	1	0	1
23	Jacksonville	1	0	1	0
22	Albany-Schenectady-Troy	0	2	2	2
22	Louisville	0	0	3	0
22	Memphis	0	0	1	0
22	New Orleans	0	0	1	0
22	Oklahoma City	0	1	0	1
22	Orlando	0	2	0	0
21	Fresno	0	1	1	1
21	Indianapolis	1	0	1	0
21	Riverside-San Bernardino-Ontario	0	0	1	0
21	Alburquerque	0	2	0	1
20	Birmingham, Ala.	0	0	1	0

Table 13, continued

20	Raleigh-Durham	0	0	0	0
20	Salt Lake City	1	1	0	1
20	Buffalo	0	0	3	1
20	Spokane	1	0	0	1
19	Nashville	0	0	1	0
19	Sacramento	1	1	0	2
19	Scranton	1	1	1	1
19	San Juan	0	1	1	1
18	Richmond, Va.	0	1	1	0
18	Columbus, O.	0	0	3	0
18	Springfield-Chicopee-Holyoke	1	1	0	2
18	Syracuse	0	0	1	0
17	Colorado Springs	1	0	0	0
17	Portland, Maine	1	1	1	0
17	Greensboro, N.C.	0	0	0	0
17	Tucson	0	1	2	1
17	West Palm Beach	0	1	1	2
17	El Paso	1	0	1	1
16	Chattanooga	0	0	0	0
16	Columbia, S.C.	0	0	1	0
16	Rochester, N.Y.	1	1	1	0
15	Allentown, Pa.	0	0	0	0
15	Eugene, Ore.	0	1	2	1
15	Grand Rapids, Mich.	0	1	1	1
15	Knoxville	0	0	1	0
15	Little Rock	0	0	0	0

Table 13, continued

15	Omaha	1	0	1	2
15	San Jose	0	0	0	0
15	Tulsa	0	0	1	0
14	Beaumont	0	0	1	0
14	Charleston, W. Va.	0	0	0	0
14	Davenport-Rock Island	0	0	0	0
14	Greenville,-Spartanburg, S.C.	0	0	1	1
14	Huntington-Ashland-Ironton (W. Va., Ky., O.)	0	0	0	0
14	Jackson	0	0	0	0
14	Lubbock	0	1	0	0
14	Madison	0	0	2	0
14	Mobile	0	1	0	0
14	Providence	1	1	0	1
14	Savannah	0	0	0	0
14	Shreveport	0	0	0	1
14	Las Vegas	0	0	0	1
13	Austin	0	0	1	1
13	Sioux Falls, S.D.	0	0	0	0
13	Akron	0	0	1	1
13	Augusta, Ga.	0	0	0	0
13	Charlotte, N.C.	0	1	0	1
13	Dayton	1	0	0	1
13	Fort Lauderdale Hollywood	0	1	0	1

Table 13, continued

13	Modesto	0	2	0	0
13	Utica-Rome, N.Y.	0	0	0	0
13	Appleton	0	1	0	0
12	Wichita	1	0	1	0
12	Charleston, S.C.	0	0	1	0
12	Des Moines	0	0	0	1
12	Duluth-Superior	0	0	1	1
12	Peoria	0	0	1	0
12	Reno	1	0	0	1
12	Roanoke	0	0	1	0
12	Santa Barbara	0	0	0	0
12	Toledo	0	1	1	0
12	Youngstown	0	1	1	1
12	Amarillo	0	0	0	0
12	Champaign-Urbana	0	0	2	0
11	Bakersfield	0	0	0	0
11	Baton Rouge	0	0	0	0
11	Boise City	0	0	0	1
11	Corpus Christi	0	0	0	0
11	Ft. Wayne	0	0	0	0
11	Harrisburg	0	0	0	0
11	Lansing	0	0	2	0
11	Lincoln	0	0	0	0
11	Montgomery	0	1	0	0
11	Odessa, Tx.	0	0	0	0
11	Oxnard/Ventura	0	1	0	0
11	Parkersburg, W. Va.	0	0	0	0
11	Pueblo	0	0	0	0

Table 13, continued

11	Springfield, Mo.	0	0	1	0
11	Takoma	0	0	1	0
11	Tallahasse	0	0	1	0
11	Winston-Salem	0	0	1	0
10	Columbus, Ga.	0	0	0	0
10	Evansville, Ind.	0	1	0	0
10	Fargo-Moorhead, N.D.	0	0	1	0
10	Anchorage	0	0	1	0
10	Atlantic City	0	0	0	0
10	Billings	0	0	0	0
10	Cedar Rapids, Ia.	0	0	1	0
10	Florence-Sheffield, Ala.	0	0	0	0
10	Huntsville	0	0	1	0
10	Kalamazoo	0	0	1	0
10	Sarasota-Bradenton	1	0	0	1
10	Terre Haute	0	0	0	0
10	Waterloo-Cedar Falls, Ia	0	0	2	0
10	Ann Arbor	NA	NA	2	0
9	Binghampton, N.Y.	0	0	1	0
9	Canton	0	0	0	0
9	Fayetteville, N.C.	0	0	0	0
9	Flint	0	0	1	0
9	Ft. Myers, Fla	0	0	0	0
9	Lancaster, Pa.	0	0	0	0
9	Lexington, Ky.	0	0	1	0
9	Macon, Ga.	0	0	0	0

Table 13, continued

9	Manchester, N.H.	0	2	0	0
9	McAllen-Pharr, Tx.	1	0	0	1
9	Monroe, La.	0	0	0	0
9	Pensacola, Fla.	0	0	0	0
9	South Bend, Ind.	0	0	0	0
9	Wheeling, W.Va.	0	0	0	0
9	Wilmington, N.C.	0	0	0	0
9	Yakima, Wash.	0	0	0	0
8	Biloxi-Gulfport, Miss.	0	0	0	0
8	Bridgeport, Ct.	0	0	0	0
8	Ft. Smith Ark.	0	0	0	1
8	Hamilton-Middletown	0	0	0	0
8	Columbia, Mo.	0	0	1	0
8	Daytona Beach	0	0	0	0
8	Eau Claire	0	1	0	0
8	Elmira	0	0	0	0
8	Green Bay	0	0	1	0
8	La Crosse, Wi.	0	0	2	1
8	Lynchburg, Va.	0	0	0	0
8	New Haven	0	0	0	1
8	Ponce, P.R.	0	0	0	0
8	Rochester, Mn.	0	0	0	0
8	Rockford, Ill.	0	0	0	0
8	Salinas, Ca.	0	0	0	0
8	Sioux City	0	0	1	0
8	Topeka	0	0	0	0
8	Worcester, Mass.	0	1	0	0

Sources: License Renewal Applications; A Public Trust, The Report of the Carnegie Commission on the Future of Public Broadcasting, Bantam Books, Inc., New York, 1979; and Broadcasting Yearbook 1979.

For explanation of market definition, see Appendix C.

Table 14A: Average Number of Commercial Seconds per Broadcast Hour, Sample of Stations in Large, Medium, and Small Markets, Georgia and Alabama

Hour ending:	Mon.	Tues.	Wed.	Thur.	Fri.	Sat.	Sun.
1:00 am	70.9	95.5	36.8	137.3	135.4	17.5	64.2
2:00 am	3.0	105.0	43.3	140.7	101.6	32.3	67.5
3:00 am	0.0	121.4	17.5	94.3	89.1	34.6	52.5
4:00 am	0.0	89.5	27.5	87.7	78.2	26.6	67.5
5:00 am	9.0	72.5	39.2	126.6	95.5	13.8	59.2
6:00 am	72.8	169.7	175.3	238.2	167.5	53.4	77.8
7:00 am	431.3	532.2	531.3	525.0	555.0	186.2	107.1
8:00 am	529.9	600.5	675.1	726.6	735.0	251.7	143.2
9:00 am	476.1	519.8	566.8	656.3	681.6	279.4	158.9
10:00 am	394.8	454.6	458.3	622.6	544.2	285.5	168.7
11:00 am	356.5	346.2	387.9	538.4	465.5	277.2	179.4
12:00 n	428.6	361.7	447.7	518.6	519.0	289.3	80.5
1:00 pm	404.7	391.5	491.6	555.5	563.5	338.0	216.7
2:00 pm	343.7	364.9	445.3	570.2	513.0	296.1	252.8
3:00 pm	376.3	329.7	425.1	562.6	514.0	274.3	261.8
4:00 pm	395.9	408.7	489.4	607.0	633.3	254.1	252.7
5:00 pm	441.9	482.3	562.7	642.8	702.9	314.1	245.1
6:00 pm	410.3	461.0	545.7	644.7	650.7	189.8	243.4
7:00 pm	328.8	373.6	391.7	582.5	550.4	133.9	223.3
8:00 pm	229.5	267.9	344.4	537.1	412.0	133.3	145.3
9:00 pm	179.0	238.5	297.1	471.4	355.2	231.9	198.2
10:00 pm	163.6	290.8	254.0	324.5	340.0	128.6	149.9
11:00 pm	145.0	191.5	205.5	279.0	289.4	121.5	129.7
12:00 pm	58.1	84.1	145.7	207.0	226.0	60.3	87.7

SOURCE: Composite Week Logs Provided by Stations with License Renewal Applications.

For each station, data were used for one day of the week.

The markets included in this sample are all the markets listed in Table 18.

Table 14B: Average Number of Commercial Seconds per Broadcast Hour, Sample of Stations in Large and Medium Sized Markets, Georgia and Alabama

Hour Ending	Mon.	Tues.	Wed.	Thurs.	Fri.	Sat.	Sun.
1:00 am	69.0	95.5	33.0	142.1	135.5	20.4	64.2
2:00	3.3	105.0	49.0	140.7	94.5	35.0	67.5
3:00	0.0	121.4	18.0	90.0	80.0	37.5	52.5
4:00	0.0	89.5	30.0	83.6	68.0	28.8	67.5
5:00	9.0	72.5	38.0	127.1	81.0	15.0	59.2
6:00	71.8	205.2	138.0	206.0	142.1	47.3	21.5
7:00	380.2	550.8	538.6	520.9	566.0	150.0	72.9
8:00	461.7	653.2	656.9	680.5	738.8	203.1	104.5
9:00	435.5	588.5	601.1	635.0	675.2	277.5	121.8
10.00	343.3	524.4	477.6	543.9	544.0	286.9	158.2
11:00	296.7	400.8	388.4	479.1	467.0	250.0	157.6
12:00 n	381.9	390.0	433.7	474.3	495.3	256.7	109.6
1:00 pm	301.9	436.8	458.2	476.8	506.0	342.8	229.8
2:00	333.7	401.8	447.6	490.5	464.8	323.9	237.9
3:00	331.4	367.5	422.9	479.8	495.0	277.5	249.8
4:00	394.5	490.8	521.1	557.7	634.0	271.4	267.9
5:00	411.2	540.5	548.7	581.8	698.9	331.1	265.6
6:00	389.8	508.5	518.4	565.8	657.8	185.0	257.4
7:00	369.4	413.5	404.7	580.8	619.5	157.3	232.3
8:00	227.5	275.5	366.3	503.1	498.6	168.8	150.6
9:00	195.6	275.0	301.3	464.7	392.5	158.1	153.1
10:00	180.6	314.6	278.3	348.8	354.2	153.5	87.5
11:00	123.8	206.2	221.8	278.8	323.3	124.6	81.6
12:00	45.0	93.1	146.4	232.6	262.5	70.0	61.3

SOURCE: Composite week logs provided by stations with License Renewal Applications.

For each station, data were used for one day of the week.

The markets included in this sample are the first 14 markets listed in Table 18.

Table 14C: Average Number of Commercial Seconds Per Broadcast Hour, Sample of Stations in Medium and Small Markets, Georgia and Alabama

Hour Ending	Mon.	Tues.	Wed.	Thurs.	Fri.	Sat.	Sun.
1:00 am	90.0	-	46.3	70.0	135.0	0.0	-
2:00	0.0	-	15.0	140.0	180.0	0.0	-
3:00	-	-	15.0	155.0	180.0	0.0	-
4:00	-	-	15.0	145.0	180.0	0.0	-
5:00	-	-	45.0	120.0	240.0	0.0	-
6:00	90.0	63.0	250.0	358.8	320.0	80.0	810.0
7:00	538.7	338.5	518.1	535.1	530.6	263.1	190.0
8:00	660.0	495.0	707.9	839.3	727.5	348.8	235.0
9:00	553.2	382.5	501.5	708.2	694.5	283.3	246.9
10 00	493.2	315.0	421.5	815.1	574.5	282.8	193.8
11:00	470.6	237.0	386.9	683.3	463.2	331.7	231.3
12:00 n	517.7	305.0	474.2	626.9	566.5	354.4	11.3
1:00 pm	601.0	301.0	555.0	747.8	678.5	328.3	185.6
2:00	362.9	291.0	440.9	765.0	609.5	240.6	284.4
3:00	462.0	254.0	429.2	727.4	552.0	267.8	287.2
4:00	398 6	244.5	429.2	791.8	632.0	219.4	220.6
5:00	500.5	366.0	589.2	819.9	710.8	280.0	201.7
6:00	453.5	366.0	597.6	585.8	636.5	200.0	210.0
7:00	191.0	285.0	368.2	690.0	412.2	83.3	203.1
8:00	240.0	250.0	306.9	500.0	238.9	56.5	60.0
9:00	462.5	170.7	287.0	507.5	270.0	391.7	920.0
10:00	272.5	229.0	195.6	221.0	306.0	64.0	1080.0
11:00	315.0	143.8	169.6	380.0	208.0	111.3	900.0
12:00	162.5	55.0	144.2	61.7	80.0	28.8	510.0

SOURCE: Composite Week Logs provided by stations with License Renewal Applications.

For each station, data were used for one day of the week.

-: means no programming broadcast in those hours.

The markets included in this sample are all the markets listed in Table 18 with the exception of the first 14 markets listed.

Table 15A: Average Number of News Seconds per Broadcast Hour, Sample of Stations in Large, Medium, and Small Markets, Georgia and Alabama

Hour Ending	Mon.	Tues.	Wed.	Thurs.	Fri.	Sat.	Sun.
1:00 am	127.3	95.5	195.7	215.6	200.6	173.3	220.0
2:00	133.2	105.0	153.3	232.5	219.8	205.2	190.0
3:00	190.0	121.4	165.8	232.5	201.8	219.1	236.0
4:00	140.0	89.5	185.8	234.4	204.5	220.1	213.0
5:00	165.0	72.5	195.8	176.3	223.6	235.9	240.0
6:00	277.4	428.8	320.7	276.3	246.0	253.2	269.5
7:00	367.2	540.3	474.3	402.6	533.8	370.9	236.1
8:00	419.0	641.7	444.0	489.4	548.7	467.9	256.6
9:00	465.4	576.0	451.3	459.4	524.7	435.4	137.5
10:00	296.1	375.7	236.8	350.2	374.0	356.4	172.7
11:00	268.3	377.7	261.8	272.3	317.0	294.0	131.0
12:00 n	317.2	387.0	266.1	317.8	286.7	275.8	185.4
1:00 pm	445.0	568.7	443.4	429.8	529.7	390.6	380.4
2:00	276.8	436.0	239.4	297.8	308.7	248.9	306.7
3:00	275.1	359.3	257.1	253.4	324.3	293.3	235.5
4:00	331.8	384.7	269.2	308.7	332.7	309.0	269.6
5:00	344.1	439.3	399.9	357.5	328.7	310.4	204.5
6:00	415.5	544.0	346.4	374.1	359.3	339.0	205.2
7:00	291.2	482.1	222.5	289.9	310.0	267.8	248.7
8:00	237.5	314.1	181.3	216.8	295.3	287.6	226.9
9:00	229.3	326.0	172.9	236.5	254.7	242.2	228.8
10:00	256.0	318.7	167.3	219.8	343.8	206.4	194.1
11:00	239.1	310.3	209.8	216.6	296.1	230.4	240.0
12:00	282.7	334.7	272.6	206.7	229.6	282.5	183.8

SOURCE: Composite Week Logs provided by stations with License Renewal Applications.

For each station, data were used for one day of the week.

The markets included in this sample are all the markets listed in Table 18.

Table 15B: Average Number of News Seconds Per Broadcast Hour, Sample of Stations in Large and Medium Sized Markets, Georgia and Alabama

Hour Ending	Mon.	Tues.	Wed.	Thurs.	Fri.	Sat.	Sun.
1:00 am	104	495	142	230	188	200	220
2:00	108	510	148	248	218	221	190
3:00	190	535	136	248	198	236	236
4:00	140	541	160	250	201	237	213
5:00	165	508	172	188	216	254	240
6:00	292	471	319	302	247	286	242
7:00	372	484	470	371	591	374	190
8:00	359	567	439	376	520	489	312
9:00	443	582	452	428	487	430	151
10:00	269	417	212	304	369	350	179
11:00	277	395	219	223	261	247	150
12:00 n	306	378	262	261	241	228	142
1:00 pm	324	520	331	280	289	274	442
2:00	239	435	227	245	224	212	307
3:00	254	350	243	222	251	238	211
4:00	318	391	263	270	292	277	234
5:00	307	464	423	287	283	268	273
6:00	305	527	333	272	254	238	202
7:00	296	459	200	221	246	246	241
8:00	207	303	127	225	273	268	242
9:00	198	270	115	211	262	204	232
10:00	228	279	107	208	327	175	195
11:00	209	295	136	204	287	249	244
12:00	258	290	211	169	242	321	196

SOURCE: Composite Week Logs provided by stations with License Renewal Applications.

For each station, data were used for one day of the week.

The markets included in this sample are the first 14 markets listed in Table 18.

Table 15C: Average Number of News Seconds per Broadcast Hour, Sample of Stations in Medium and Small Markets, Georgia and Alabama

Hour Ending	Mon.	Tues.	Wed.	Thurs.	Fri.	Sat.	Sun.
1:00 am	360.0	-	330.0	0.0	270.0	0.0	-
2:00	360.0	-	180.0	0.0	240.0	0.0	-
3:00	-	-	315.0	0.0	240.0	0.0	-
4:00	-	-	315.0	0.0	240 0	0.0	-
5:00	-	-	315.0	0.0	300.0	0.0	-
6:00	30.0	302.0	324.0	180.0	240.0	100.0	320.7
7:00	357.6	653.0	482.0	480.0	406.7	363.8	322.5
8:00	553.6	791.0	453.0	766.7	606.0	423.3	138.8
9:00	508.2	564.0	450.0	536.1	600.0	446.7	108.8
10:00	347.7	293.0	284.0	463.3	384.0	370.0	159.4
11:00	251.8	343.0	286.0	392.8	429.0	393.3	90.6
12:00 n	338.6	405.0	274.0	456.7	378.0	376.7	277.5
1:00 pm	675.9	660.0	657.0	796.1	1011.0	636.7	249.4
2:00	349.1	438.0	263.0	426.7	498.0	326.7	306.1
3:00	315.5	378.0	284.0	330.0	471.0	410.0	281.7
4:00	358.2	372.0	281.0	403.3	414.0	376.7	336.7
5:00	414.9	390.0	356.0	530.0	420.0	400.0	75.0
6:00	647.4	578.0	372.0	601.1	570.0	570.0	352.6
7:00	275.0	533.3	263.0	600.0	438.0	315.0	265.0
8:00	400 0	341.3	274.3	180.0	340.0	330.0	0.0
9:00	480.0	430.0	312.0	345.0	274.3	325.0	180.0
10:00	480.0	422.0	312.0	270.0	384.0	288.0	180.0
11:00	480.0	360.0	372.0	270.0	318.0	192.0	180.0
12:00	480.0	480.0	408.0	420.0	180.0	157.5	0.0

SOURCE: Composite Week Logs provided by stations with License Renewal Applications.

For each station, data were used for one day of the week.

-: means no programming broadcast in those hours.

The markets included in this sample are all the markets listed in Table 18 with the exception of the first 14 markets listed.

Table 16A: Average Number of Public Affairs Seconds per Broadcast Hour, Sample of Stations in Large, Medium, and Small Markets, Georgia and Alabama

Hour Ending	Mon.	Tues.	Wed.	Thurs.	Fri.	Sat.	Sun.
1:00 am	158.1	21.00	17.1	11.2	5.0	247.8	15.0
2:00	44.4	15.0	10.0	15.0	4.5	0	15.0
3:00	200.0	15.0	15.0	15.0	5.4	0	20.0
4:00	270.0	76.0	10.0	73.1	5.4	0	10.0
5:00	15.0	110.0	10.0	120.0	5.4	231.2	9.0
6:00	100.8	66.0	12.0	64.7	47.1	105.4	364.0
7:00	81.5	141.6	26.5	41.1	84.8	11.7	420.6
8:00	71.1	38.7	37.1	11.6	2.0	34.2	290.3
9:00	118.7	48.0	90.0	13.4	18.0	18.3	136.6
10.00	34.5	90.6	109.2	14.9	114.0	12.3	146.2
11:00	32.3	53.6	35.7	93.6	83.3	69.7	160.2
12 00 n	28.1	42.0	89.4	17.0	34.6	141.1	2.7
1:00 pm	154.3	28.0	44.1	30.7	18.0	105.9	62.2
2:00	21.0	146.0	24.7	98.1	106.0	81.4	117.4
3:00	31.3	162.0	139.7	28.7	131.3	139.1	39.2
4:00	54.1	24.0	15.4	13.4	138.6	1.0	4.5
5:00	39.9	36.0	40.2	9.2	72.0	10.6	13.7
6:00	34.6	73.6	21.2	24.8	78.0	71.5	86.3
7:00	31.6	93.0	55.0	32.4	80.0	15.7	19.0
8:00	37.7	117.5	46.0	16.3	126.4	15.7	123.7
9:00	18.7	99.8	103.7	11.3	87.6	41.0	7.5
10:00	44.1	181.4	25.0	.0	3.5	10.0	185.6
11:00	30.9	176.0	46.7	8.0	3.5	0	120.0
12:00	195.7	164.3	50.4	45.0	4.0	10 5	232.5

SOURCE: Composite Week Logs provided by stations with License Renewal Applications.

For each station, data were used for one day of the week.

The markets included in this sample are all the markets listed in Table 18.

Table 16B: Average Number of Public Affairs Seconds Per Broadcast Hour, Sample of Stations in Large and Medium Sized Markets, Georgia and Alabama

Hour Ending	Mon.	Tues.	Wed.	Thurs.	Fri.	Sat.	Sun.
1:00 am	174	21	18	12	6	286	15
2:00	46	15	12	16	5	0	15
3:00	200	15	18	16	6	0	20
4:00	270	76	12	78	6	0	10
5:00	15	110	12	128	6	249	9
6:00	150	48	12	82	30	128	392
7:00	7	58	33	58	108	17	593
8:00	19	6	40	11	3	22	427
9:00	56	15	120	19	27	27	201
10:00	27	34	22	21	171	16	215
11:00	35	40	42	132	125	46	218
12:00 n	30	51	105	24	52	208	4
1:00 pm	235	27	31	27	27	93	5
2:00	32	165	22	21	144	120	109
3:00	32	33	207	16	137	205	60
4:00	56	18	11	8	199	0	7
5:00	55	24	44	13	96	3	21
6:00	14	91	15	36	117	86	7
7:00	41	119	39	23	105	23	28
8:00	43	167	28	20	173	23	132
9:00	19	126	117	14	126	60	8
10 00	46	242	18	0	5	0	198
11:00	31	221	8	10	5	0	128
12:00	207	203	27	0	5	0	248

SOURCE: Composite Week Logs provided by stations with License Renewal Applications.

For each station, data were used for one day of the week.

The markets included in this sample are the first 14 markets listed in Table 18.

Table 16C: Average Number of Public Affairs Seconds per Broadcast Hour, Sample of Stations in Medium and Small Markets, Georgia and Alabama

Hour Ending	Mon.	Tues.	Wed.	Thurs.	Fri.	Sat.	Sun.
1:00 am	0.0	-	15.0	0.0	0.0	0.0	-
2:00	30.0	-	0.0	0.0	0.0	0.0	-
3:00	-	-	0.0	0.0	0.0	0.0	-
4:00	-	-	0.0	0.0	0.0	0.0	-
5:00	-	-	30.0	0.0	0.0	0.0	-
6:00	30.0	120.0	12.0	0.0	150.0	0.0	0.0
7:00	156.0	309.0	15.0	0.0	33.3	0.0	51.4
8:00	193.6	104.3	32.0	13.3	0.0	60.0	0.0
9:00	238.6	114.0	33.0	0.0	0.0	0.0	0.0
10:00	49.1	204.0	275.0	0 0	0.0	3.3	0.0
11:00	27.3	81.0	24.0	0.0	0.0	120.0	37.5
12:00 n	24.5	24.0	60.0	0.0	0.0	0.0	0.0
1:00 pm	0.5	30.0	69.0	40.0	0.0	133.0	183.8
2:00	0.0	108.0	30.0	286.7	30.0	0.0	133.3
3:00	30.0	420.0	12.0	60.0	120.0	0.0	0.0
4:00	50.5	36.0	24.0	26.7	18.0	3.3	0.0
5:00	8.2	60.0	33.0	0.0	24.0	26.7	0.0
6:00	78.0	39.0	33.0	0.0	0.0	38.6	255.5
7:00	0.0	45.6	84.0	75.0	30.0	0.0	0.0
8:00	10.0	0.0	77.1	0.0	33.3	30.0	0.0
9:00	15.0	51.4	48.0	0.0	0.0	0.0	0.0
10.00	15.0	24.0	42.0	0.0	0.0	36.0	0.0
11:00	30.0	30.0	132.0	0.0	0.0	0.0	0.0
12:00	15.0	35.0	102.0	300.0	0.0	45.0	0.0

SOURCE: Composite Week Logs provided by stations with License Renewal Applications.

For each station, data were used for one day of the week.

-: means no programming broadcast in those hours.

The markets included in this sample are all the markets listed in Table 18 with the exception of the first 14 markets listed.

Table 17

Selected Reasons for Preferring A Particular Station, By Station's Format

(Based in each case on those identifying a favorite station that has the specified format)

Which of these reasons best describes why ______ is your overall favorite station?"	Favorite Format is: Middle of the Road	Contemporary	Country	Beautiful Music
Good local news coverage	35.6%	10.5%	22.9%	17.5%
Plays the one kind of music I prefer	35.3	57.3	70.7	78.6
Habit of listening to it	18.3	25.7	17.2	13.5
Announcers/disk jockeys I especially like	18.0	14.6	14.6	5.6
Network news and network programs	12.1	5.8	11.5	6.3
Good reception-comes in loud and clear	9.5	12.3	12.7	11.9
Fewer commericals	7.5	11.7	4.5	17.5
Community announcements and information	7.2	6.4	9.6	3.2
Community affairs dealing with local issues	4.9	.6	5.7	3.2
Good play-by-play of sports events	4.9	.6	3.8	2.4
Easy to find on the dial	2.3	5.3	5.1	2.4
Plays a variety of music	1.3	3.5	----	2.4
Contests with good prizes	1.3	.6	2.5	----
Other Reasons	6.9	2.9	5.7	4.0
No answer	----	----	.6	2.4
Total Number of Responses	306	171	157	126

Note: Multiple mentions, need not total 100%.

Source: AP Research, "Radio News Listening Attitudes," (Magid Study), pp.4B, 6B, 7B, 8B.

Table 18: Incidents of Commercial Time Equalling or Exceeding 18 Minutes, Sample of Markets in Georgia and Alabama

Markets 1/	Total Number of Observa- tions 2/	Number of incidents of 18 minutes or more	Number of Stations with incidents of 18 minutes or more
Atlanta (31, 24)	492	1	1
Birmingham (20, 17)	326	3	1
Savannah (14, 13)	282	0	0
Mobile (14, 11)	180	0	0
Augusta (13, 9)	184	0	0
Montgomery (11, 11)	213	0	0
Columbus (10, 8)	163	4	2
Huntsville (10, 8)	170	1	1
Florence (10, 10)	199	4	1
Macon (9, 9)	167	1	1
Albany (7, 7)	136	9	4
Tuscaloosa (7, 6)	122	1	1
Gadsden (5, 4)	79	0	0
Anniston(4, 3)	61	0	0
Decatur (5,5)	102	9	2
Auburn-Opelika (4,2)	45	8	1
Jasper (3,3)	46	2	2
Jessup (3,3)	48	0	0
Milledgeville (3,3)	49	4	1
Moultrie (3,3)	46	0	0
Thomson (3,3)	51	0	0
Alexander City (2,2)	34	0	0
Calhoun (2,2)	26	0	0
Cartersville (2,2)	33	0	0
Dawson (2,2)	29	1	1
Ft. Payne (2,2)	31	0	0
Hamilton (2,2)	30	0	0
Manchester (2,2)	39	4	1
Monroeville (2,2)	31	0	0
Russellville (2,1)	12	0	0
Warner-Robins (2,2)	31	0	0
West Point (2,1)	15	0	0
York (2,1)	10	0	0

1/ The numbers in parentheses represent, respectively, the total number of stations in the market (See Appendix A for market definitions) and the number of stations in the sample.

2/ For each market in the sample, one day was chosen from the composite week.

Table 18, continued

Alma (1,1)	14	0	0
Arab (1,1)	16	0	0
Baxley (1,1)	13	0	0
Bremen (1,1)	12	1	1
Claxton (1,1)	13	0	0
Centerville (1,1)	12	0	0
Covington (1,1)	12	0	0
Elba (1,1)	14	0	0
Evergreen (1,1)	11	0	0
Flomaton (1,1)	13	0	0
Ft. Valley (1,1)	12	0	0
Gordon (1,1)	18	0	0
Greenville (1,1)	14	0	0
Hazelhurst (1,1)	18	1	1
Louisville (1,1)	17	0	0
Luverne (1,1)	11	0	0
Opp (1,1)	14	0	0
Piedmont (1,1)	12	0	0
Rainsville (1,1)	15	0	0
Reidsville (1,1)	13	0	0
Royston (1,1)	12	0	0
Soperton (1,1)	14	0	0
Sylvania (1,1)	16	0	0
Tallasee (1,1)	13	0	0
Vernon (1,1)	12	0	0

Source: Composite Week Logs Provided by Stations in License Renewal Applications.

Table 19: Incidence of Various Levels of Commercial Time, Stations in a Sample of Markets in Georgia and Alabama

	Number of Seconds of Commercial Time					
Market 1/	1080 or more	950-1079	800-949	600-799	300-599	less than 300
Atlanta (31, 24)	1	13	30	49	152	247
Birmingham (20, 17)	3	5	12	47	98	161
Savannah (14, 13)	0	2	3	19	74	184
Mobile (14, 11)	0	1	0	20	64	97
Augusta (13, 9)	0	7	4	16	30	127
Montgomery (11, 11)	0	0	1	27	80	105
Columbus (10, 8)	4	6	12	10	40	91
Huntsville (10, 8)	1	1	10	17	67	74
Florence (10, 10)	4	12	12	26	68	77
Macon (9, 9)	1	10	16	18	68	77
Albany (7, 7)	9	11	10	7	32	67
Tuscaloosa (7, 6)	1	1	8	21	36	55
Gadsden (5, 4)	1	2	1	23	21	31

1/ The numbers in parentheses represent, respectively, the total number of stations in the market (see Appendix A for market definitions) and the number of stations in the sample.

Table 19 (continued)

Anniston (4, 3)	0	1	1	8	16	35
Decatur (5, 5)	9	0	12	20	19	42
Auburn-Opelika (4, 2)	8	3	3	6	7	18
Jasper (3, 3)	2	3	9	6	9	17
Jessup (3, 3)	0	0	2	10	20	16
Milledgeville (3, 3)	4	2	10	11	12	10
Moultrie (3, 3)	0	1	2	7	15	21
Thomson (3, 3)	0	0	1	7	10	33
Alexander City (2, 2)	0	0	4	5	11	14
Calhoun (2, 2)	0	0	0	0	3	23
Cartersville (2, 2)	0	1	0	2	18	12
Dawson (2, 2)	1	3	4	3	1	17
Ft. Payne (2, 2)	0	0	0	2	9	20
Hamilton (2, 2)	0	2	1	3	14	10
Manchester (2, 2)	4	3	3	4	4	21
Monroeville (2, 2)	0	0	0	5	7	19
Russellville (2, 1)	0	0	1	8	3	0

Table 19 (continued)

Warner-Robins (2, 2)	0	0	0	1	9	21
West Point (2, 1)	0	0	1	1	9	4
York (2, 1)	0	0	0	0	4	6
Alma (1, 1)	0	0	1	3	8	2
Arab (1, 1)	0	0	0	2	10	4
Baxley (1, 1)	0	0	2	6	5	0
Bremen (1, 1)	1	3	4	4	0	0
Claxton (1, 1)	0	0	1	3	6	3
Centerville (1, 1)	0	0	0	0	0	13
Covington (1, 1)	0	0	0	0	4	8
Elba (1, 1)	0	2	3	5	3	1
Evergreen (1, 1)	0	0	0	1	2	8
Flomaton (1, 1)	0	0	0	0	0	13
Ft. Valley (1, 1)	0	0	0	2	8	2
Gordon (1, 1)	0	0	0	3	12	3
Greenville (1, 1)	0	1	1	2	7	3
Hazlehurst (1, 1)	1	0	2	2	5	2

Table 19 (continued)

Louisville (1, 1)	0	1	3	6	3	4
Luverne (1, 1)	0	0	0	0	0	11
Opp (1, 1)	0	0	0	0	1	13
Piedmont (1, 1)	0	0	0	0	5	7
Rainsville (1, 1)	0	0	0	2	6	7
Reidsville (1, 1)	0	0	1	2	9	1
Royston (1, 1)	0	0	0	3	7	2
Soperton (1, 1)	0	1	4	3	4	2
Sylvania (1, 1)	0	0	0	0	5	11
Tallasee (1, 1)	0	0	0	0	5	8
Vernon (1, 1)	0	0	1	4	5	2

Source: Composite Week Logs Provided by Stations in License Renewal Applications.

Separate Statement of Charles D. Ferris, Chairman Re Radio Deregulation

September 6, 1979.

The action we have proposed today is a new step in our continuing effort to seek and find more effective and efficient ways to make communications responsive to public needs. We have accepted the challenge of Congress, the President, and the American people to take a fresh look at the continuing relevance of regulation in a dramatically changing communications marketplace. We have already started this process in cable television and telephone regulation. Today we start that process in radio broadcasting.

The data contained in the Notice adopted today indicates that in radio broadcasting, the public interest can be met most effectively by the forces of competition in the radio marketplace.

For many years detailed FCC regulation of radio was thought essential to guarantee that the voices of a few would not so dominate the airwaves as to drown the dissenting opinions and tastes of many others. Today the data in this Notice indicates that as the number of radio stations has dramatically increased, listeners have been offered a wider range of choices, largely despite, rather than because of, government regulation.

In each of the areas we propose to deregulate, our preliminary data reveals that radio stations have by and large exceeded the requirements government has imposed. Survival in a competitive marketplace appears to require radio stations to impose upon themselves a heavier burden of responsiveness to community needs than has government regulation.

But, in order for deregulation in any form to work well, we must remain committed to keeping the marketplace competitive, and increasing its capacity to respond directly to consumer needs. Those areas of radio regulation where we have been most effective—using structural tools such as the enforcement of stringent Equal Employment Opportunity requirements, programs to encourage minority ownership, and measures that will increase the number of stations by more efficient use of the spectrum—become even more critical.

By removing ineffective government involvement, we will free our limited resources to enable us to promote more aggressively a competitive and responsive radio marketplace. The action we propose today is thus more than deregulation. It marks a new view of government's role in this field. It is a proposal for more effective communications regulation, one that recognizes the sensitivity of government involvement in programming decisions and the importance of stimulating a competitive market environment that can serve the same goals.

It may be that in this case additional data will show us wrong in our preliminary view that the radio marketplace is one ripe for this shift in government enforcement resources. But to me the most important fact is that this proceeding shows that a federal agency is capable of zero-basing its regulatory scheme, accreted over a 45-year period, in an attempt to look for a better way.

Concurring Statement of Commissioner Robert E. Lee in Re: Deregulation of Radio

I agree completely with the issuance of a notice raising questions about our historic interpretation of our statutory mandate and our role as regulators. I am concurring because I don't feel wedded to any particular language or proposal. I want to gather as much information as possible about the legal, economic and practical consequences of all the alternatives here so that, when this is over, everyone will be better off.

Statement by FCC Commissioner James H. Quello

September 6, 1979.

Re: Modification or elimination of Commission rules and policies pertaining to commercial AM and FM radio in the areas of nonentertainment programming, ascertainment, commercialization and related fields.

In going forward with this important rulemaking at this time, the Commission has taken an important first step toward deregulation of radio broadcasting. I believe we should continue our efforts to remove wasteful, unnecessary and obstructive government oversight from a highly competitive industry which is fully responsive to the marketplace.

The deregulatory thrust of this notice is timely and sensible. If the first of the options for each of the proposed rules are finally adopted they would provide substantial deregulation, reduced bureaucracy and a concomitant reduced cost of government in keeping with the mood and will of the American taxpayers today. It should also contribute to a less litigious, freer and better broadcast service.

While some of my colleagues have expressed misgivings regarding the self-regulating effects of the marketplace, I have no such concerns. Experience has taught me that the marketplace is a very good regulator indeed. Moreover, the Commission's own data, compiled in support of today's action, shows very clearly that the marketplace and public acceptance, not regulation, is responsible for advancing the radio broadcasting industry in this country to its present pre-eminence in the world.

The time has long since passed when local radio broadcasters and their audiences require extensive oversight from Washington. Virtually all radio markets are replete with diversity, competition and ample incentive to provide good service. It's heartening to note that our data bear out what my own broadcast experience taught me long ago; a broadcaster competing in his own self-interest will go to great lengths to identify the diverse interests which make up his market and then do his best to provide those interests with the best service possible. There are many more radio stations today than TV or newspapers in every sizable market. In many markets there is almost a surplus of radio stations—there is an automatic and constant search for unserved or new program needs.

Today's Commission action seeks comment upon a wide range of options and I applaud the breadth of this approach. It should be understood, however, that primary focus should be placed upon the *first* of the various options which constitute the recommendations of the Commission staff. Considering the natural tendency of regulators to regulate, I believe that the staff should be supported in its conclusion that there are some facets of radio regulation which should be left to marketplace forces and not controlled from Washington. If I were required to take final action today, I would support the staff recommendations. Before taking final action, however, I expect to take full advantage of a wide range of comments which I am confident will help to sharpen and clarify all of the issues and which will provide a full and complete record upon which to base a reasoned and thoughtful judgment.

Arbitrary levels of non-entertainment programming serve no useful public purpose. It is clear from our data and from even a minimal exposure to the broadcasting services that non-entertainment programming is demanded by the public. It is *equally clear* that *news and public affairs programming are not demanded by all of the public all of the time.* The marketplace—the public taste, and not regulation—should determine how much, what kind and at what times during the broadcast day such programming is broadcast. I believe greater responsiveness to legitimate public needs comes about through public acceptance or rejection in the area served by radio broadcasters.

Arbitrary commercial limitations likewise serve no useful purpose. Stations which persist in exceeding reasonable bounds of commercialization risk and suffer public disaffection. They invariably find that the benefits are short-lived and the marketplace quickly establishes a point of diminishing returns.

The onerous process of ascertainment of community needs and interests, as defined in great detail by this Commission, is a mechanistic exercise which has only served to elevate form over substance. A broadcaster, if he is to survive and prosper, must in his own way know and ascertain his community.

It should be remembered that regulation—all regulation—places a burden upon not only those who must directly submit to regulation but upon everyone. Regulation is not free. Tax dollars must support the work of this Commission. To the extent that work is meaningless or counter-productive, those tax dollars are squandered. I believe those rules and policies considered in today's action clearly fall into those categories.

The public has much to gain by taking a very serious interest in today's action. Broadcasters and non-broadcasters alike should take the time and put forth the effort to examine the issues and provide the Commission with their best thinking. The Commission, in turn, bears the responsibility to put aside narrower interests and to make its decision on the basis of providing the best service to the most people at the lowest costs.

I believe the FCC should continue its deregulatory thrust in the future, but I realize our efforts are limited in scope by the Communications Act. Only legislation can provide major deregulation dealing with license terms, political broadcasting, government involvement in program format and alternatives to the comparative hearing process. I hope some time in the near future the FCC will take appropriate action to deliberate and make recommendations for deregulatory legislation.

My views advocating complete deregulation have been presented before the House and Senate Subcommittees on Communication. The broad deregulatory viewpoints expressed are so relevant to the essence of this rulemaking process that I am including pertinent excerpts as an addendum to this statement.

Addendum to Statement by FCC Commissioner James H. Quello

September 6, 1979.

Re: Modification or elimination of Commission rules and policies pertaining to commercial AM and FM radio in the areas of non-entertainment programming, ascertainment, commercialization and related fields.

September 13, 1978.

Comments of FCC Commissioner James H. Quello on Title IV, H.R. 13015 Before the House Subcommittee on Communications

I propose clean, decisive, legislative surgery to remove the major pervasive defects and massive economic wastes of broadcast regulation. Unequivocally remove all First Amendment and regulatory constraints! *Subject broadcasting to exactly the same regulations and First Amendment constraints as its major competitor and closest cousin—newspapers.* This also means eliminating the nebulous, troublesome and out-dated "public interest" standard.

In return, assess broadcasts a practical spectrum usage fee and provide for open marketplace addition of stations that meet reasonable standards of engineering feasibility.

The time has never been more propitious.

This action would most effectively and forcefully implement the visionary main thrust of H.R. 13015—that regulation should be necessary only "to the extent marketplace forces are deficient." *In other words, wherever the market is open and competitive, regulations should be abolished. This certainly applies to broadcasting markets in this country where intense competition exists and is growing apace.* Broadcasters not only compete aggressively against each other, but also with all other media including newspapers, magazines, outdoor advertising, transportation advertising, direct mail, etc. It's time to remove regulations and allow competitive market forces to operate. This would provide massive deregulation, reduced bureaucracy and a resulting reduction in government costs—all in keeping with the current trend and mood of the American public. Then, too, the *public* would *benefit* from a freer, more robust, more venturesome broadcast journalism emancipated from unnecessary restrictive government oversight.

The views expressed here and the supporting arguments to be presented are my own and do not represent an official FCC view. I fully realize that court interpretations and a continuing variety of adversary viewpoints are formidable considerations for legislative action or reform. *I am also fully cognizant that present FCC decisions and deliberations must be based on the current Communications Act and existing case law and not on proposed legislative action or re-write.* However, I am proposing substantial revision from the unique perspective of over four years FCC service and over twenty-five years in broadcasting. Also, I note that Henry Geller, respected communications lawyer and new head of the National Telecommunications and information Administration, is a staunch advocate of First Amendment rights. He was quoted by Les Brown of the New York Times: "The more we let radio and television be the way print is, the better off we are. Let the marketplace answer whether there should be more networks, not the FCC," I also agree with Mr. Geller's statement in the August 1979 issue of the RTNDA publication where he was quoted: "I think the Fairness Doctrine does impose First Amendment restraints. I think, as I testified recently before the Congress, that if you scrap the public trustee scheme entirely in order to accomplish goals through other means—means of spectrum usage tax or others—that that's very worthy of exploration and that's what re-write is about." I repeat the quote here as a reminder there are knowledgeable people of worthy purposes questioning the propriety of the public trustee concept as applied to current broadcast regulations.

I believe government or court-mandated First Amendment restrictions and also the government-mandated public trustee concept are outdated and no longer justifiable in today's competitive technological, economic and journalistic climate in communications.

In fact, broadcasting was not initially formulated as a public trusteeship. It was actually conceived as an advertising supported, risk capital, commercial enterprise. No government funds were appropriated to finance pioneer broadcast service or to initiate commercial service. Much has been said of the people's airways or the public trustee concept—perhaps, too, because by sheer continued repetition over the years it has become accepted as a fact. However, Eric Sevareid, who said so many things so well over the years, once commented:

"I have never understood the basic legally governing concept of 'the people's airways.' So far as I know there is only the atmosphere and space. There can be no airway, in any practical sense, until somebody accumulates the capital, know-how, and enterprise to put a signal into the atmosphere and space."

As a former newsman, I have always hoped that some day broadcasting would be treated the same as other journalistic and advertising media. With continuing debate and various court interpretations, it seems this can best be achieved by bold, innovative legislative action. In my opinion, the time has finally come to grant full Constitutional rights of freedom of the press and freedom of speech to broadcasters. This would end years of discriminatory treatment which is no longer justifiable with today's massive competition in all communications media.

There are many more TV and radio stations today than newspapers in every sizable market. The growth of cable, translators, UHF, FM and the development of satellites has provided more media availability than ever before. Future potential is practically unlimited. Then, too, broadcast journalism today is mature, professional and objective as any media. Regulatory restraints are no longer justified in today's era of competitiveness, numerous outlets and professional journalism.

The scarcity argument justifying governmental intervention in broadcasting seems more specious today than when it first crept into court decisions years ago that limited First Amendment guarantees for broadcasters.

There are limitations upon the numbers of businesses of any kind in a given community. Limited spectrum "scarcity" arguments once embraced by the courts should hardly apply in today's abundance of radio-TV media compared with newspapers. Economic reality is a far more pervasive form of scarcity in all forms of business whether in broadcasting, newspapers, auto agencies or selling pizza. It is a fact that not everyone who wants to own a broadcasting station in a given community can do so. It is also an economic fact that not everybody who wants to own a newspaper, an auto agency or a pizza parlor in a given community can do so.

I believe the public would be served by abolishing Section 315 including the Fairness Doctrine and Section 312(a)(7). The Fairness Doctrine is a codification of good journalistic practice. Its goals are laudatory. However, I no longer believe government is the proper source for mandating good journalistic or program practice. I believe the practice of journalism is better governed by professional journalists, editors and news directors. Programming is best done by professional program directors, producers and talent. Even with some programming deficiencies, a government cure with censorship overtones is worse than the industry disease.

There is little doubt that if TV and radio had existed in 1776, our founding fathers would have included them as prime recipients of the Constitutional guarantees of freedom of the press and freedom of speech. After all, they were *guaranteeing citizens these freedoms* so that a well-informed public and electorate could vote on issues and candidates—free of any semblance of government interference or control. *The Constitutional freedoms were instituted for the benefit of the citizenry—the total public—rather than the media. It is the public that stands to gain from an all media freedom of the press.*

Section 315 and Section 312(a)(7) guarantee access to broadcasting in order to seek political office. This is not required of newspapers and magazines because of the Constitutional guarantees accorded only to print journalism. Clearly print journalism, with its guaranteed "freedom of the press" has risen to the task of informing the electorate and uncovering illegal or unethical practices without government interference or regulation—I see not reason to assume broadcast journalists or executives are any less responsible or diligent. Broadcast journalists have earned and rightfully deserve all Constitutional freedoms.

I believe that removing the government restraints of Section 315, including the Fairness Doctrine and Section 312(a)(7), would free broadcast journalism, foster more comprehensive and independent reporting and better serve the American people.

I'd like to emphasize that my plea is not for freedom from program regulation for broadcasters. I am appealing for freedom from program regulation for the public at large. My experience in broadcasting and with the FCC leads to the firm belief that far too much programming provides no useful function except to satisfy some rule or regulation of the FCC. I have an equally firm belief that much controversial programming which could be of great service to the public is avoided by licensees wary of government requirements.

It is ironic that the regulated—while vociferously complaining about their over-regulated status—are often the last who wish to see this yoke lifted. It is well recognized that regulation carries with it a measure of protection from competition and without regulation there is no such protection. I believe that there are areas of telecommunications which do not readily lend themselves to a totally competitive environment (like telephones), but I don't believe that broadcasting is one of them. It is obvious to anyone familiar with the industry that competition is already very strong in many markets and it could be an even stronger force without the regulatory constraints which have developed over the years. The public stands to benefit from this potential but not until it is given full opportunity to develop.

I would guess that most large broadcasters may view my proposals with at least mild alarm since they are best able to cope with the maze of regulations and restrictions which we impose. They are able to maintain counsel, hire expert personnel and buy or produce programming to satisfy the public and the government. Presumably, they would prefer "business as usual" to any wide-ranging deregulatory scheme which might contain the seeds of greater competition. My proposals, then, are not calculated to garner wide support among existing licensees. Rather, they are meant to establish a climate whereby the American public can receive more, freer and better broadcasting service. I believe it is a proper goal of the Communications Act of 1934 and of the First Amendment to the Constitution and I believe it is a proper goal for the new Communications Act.

Broadcast licensees should be assessed an appropriate annual spectrum fee and then assigned licenses without expiration dates. At present, broadcast licensees must prepare lengthy applications for license renewal every three years. These applications are then reviewed by the Commission, which must find that renewal is or is not in the public interest. The applications are further subject to challenge from members of the licensee's audience under the very loose application of the principles of standing as a party in interest.

For most licensees, the triennial shipment of pounds of paper to Washington, D.C. is ritualistic, time-consuming, expensive and nonproductive. In the vast majority of instances, the Commission makes the public interest finding that permits renewal and the three-year cycle begins anew. In a few cases, renewal is delayed by objections from members of the public. In very few cases, the licensee is forced into a hearing to determine whether he is fit to remain a licensee. And, there are many instances where other parties file "on top" of the licensee in an effort to gain the license for themselves.

The process of license renewal appears to be a very expensive, time-consuming method of ferreting out those few licensees who have failed to meet a subjective "public interest" standard of performance. With adoption of a free marketplace concept similar to newspapers, license renewal would no longer be required. The enormous savings in time and money could be used for more constructive purposes in programming and news.

Some would contend that license renewal time offers the Commission the only real opportunity it has to review the overall performance of its licensees. However, I believe greater responsiveness to legitimate public needs comes about through public acceptance or rejection in the area served by the broadcaster.

What rules would then govern broadcasters? The same law and rules as newspapers or other businesses or professions—criminal codes, libel, slander laws, anti-trust laws, EEOC requirements, SEC requirements, etc. There is no need for discriminatory singling-out of broadcasting for special restrictive regulations—broadcasters generally are as responsible, dedicated and every bit as socially-conscious as other Americans—in media, industry, professional or government groups. Most feel a self-imposed public trusteeship. The few incompetents and miscreants fail and lose their business or jobs or run afoul of the law as in any other profession or business.

Also I believe news objectivity and overall fairness and efficiency are better assured through professional broadcast and print journalists and through professional program executives. Many government-appointed officials, regardless of how well meaning, are handicapped by lack of experience and little understanding of media operations or the practicalities and economics of running a communications business.

Past considerations of the renewal issue have included the argument that a license "in perpetuity" would greatly weaken the competitive spur in the Communications Act. It must be remembered that broadcasting stations, although licensed, are also private business enterprises backed by private capital, subject to the risks and opportunities of entrepreneurship. Broadcasters have no incentive to offend or alienate potential audiences; on the contrary, it just makes good business sense to attempt to serve as much of the potential audience as possible and as well as possible. All media and particularly broadcasting require public acceptance to succeed and even survive. Regulation is supposed to be a rather imperfect substitute for competition where competition either doesn't exist or is restrained by certain market forces. In practically all of the broadcasting markets in this country, competition not only exists but is intense and growing. As stated before, broadcasters not only compete among themselves but with all other media including newspapers, magazines, outdoor advertising, direct mail, etc. Therefore, it would seem reasonable to remove as much regulation as possible in order to permit competitive market forces to operate.

One immediate beneficial effect of open market competition would be elimination of government involvement in news and programming—where it never belonged in a free society.

There are many areas requiring continued government direction and surveillance but not a major news and information medium in a government conceived in and dedicated to the principles of free speech and a free press. I want the record to indicate that I advocate government involvement in appropriate areas—government involvement and direct action was required to attain such desirable goals as social security, minimum wages, FDIC protection for savings, civil rights, medicare and public health, anti-trust rules and environmental protection. Government must continue a vital role in solving problems in energy, national security, urban decay, equal rights and lagging economy.

Also there is a continuing need for consumer activist participation against products, organizations and services that mislead or bilk the consumer. Broadcasting should benefit from such interest but on the very same basis as any other news media. Broadcasting needs full, unfettered press freedom to report, clarify, editorialize and advocate on all events and controversies subject to the same marketplace constraints and criticism as newspapers or magazines. This includes expanding its already active role in exposing consumer frauds and unsavory corporate, public and governmetal practices.

The argument that removing the public interest standard would permit broadcasters to eliminate news, public affairs or meaningful programs is indeed specious. It would be contrary to all industry trends and to broadcasting self-interest to eliminate or minimize news and information programming. Broadcast journalism and public affairs are increasing in importance. I believe the major impact of TV and radio on the American way of life today is in news and news analysis—not in entertainment programs. I think most people agree that broadcasting today is most remembered and respected for its hours of exceptional journalism—and that the greatest benefit most Americans derive and expect from broadcasting is information. Recent research indicates more Americans are getting initial news from TV and radio than from newspapers. This potential for molding public opinion poses an enormous responsibility and opportunity. No practical broadcaster will ignore the audience mandate for comprehensive objective coverage of news and public affairs. I firmly believe that full First Amendment rights will generate more top level management emphasis on news and public affairs. Owners, executives and broadcast managers of the future will more and more assume roles of publishers and editors-in-chief. With full press freedom, stations and networks will have added incentive for editorializing and for larger news staff capable of more investigative and detailed "one the spot" reporting.

Once more, I believe in freedom of speech and freedom of the press for all media. This freedom best serves the overall public unfettered by government pressure or by citizen activists groups demanding special broadcast consideration for their own private social and political philosophies through government-mandated access. I further believe newsmen have the right to be wrong and that news executives have the responsibility of seeing that they are not wrong too often. I believe newsmen have the right and obligation to seek the truth—the facts. I also believe freedom of speech applies to government officials—they should be able to criticize the press, including the broadcast press, without raising the ominous spectre of censorship because of possible regulatory oversight.

In conclusion, I repreat that with today's intensely competivie broadcast news and advertising media, there is no logical reason for the special discriminatory regulation of broadcasting:

The laudable deregulatory thrust of HR 13015 should be specifically implemented by granting broadcasting full First Amendment rights and removing all regulatory restraints. The overall public would be the important beneficiaries through massive deregulation, reduced litigation, reduced bureaucracy and a resulting reduced cost to taxpayers. With elimination of renewals, petitions and unnecessary rulemakings, the FCC staff (which included 332 attorneys at last count) could be systematically reduced by probably as much as 40%. The principal remaining broadcast function would be engineering spectrum allocation and enforcement. The bureau reduction could be gradully accomplished through attrition, via transfer, resignation and retirement.

The reduction in bureau staff and government expenses would be in keeping with the mood and will of the American public today. I believe this total proposal would pass convincingly today in any objective public referendum.

Moreover, removing the government restraints of Section 315 and 312 would free broadcast journalism, foster more comprehensive and independent reporting and better serve the American people.

Commercial AM and FM Radio Deregulation Broadcast Agenda Item #2, September 6, 1979

Statement of Commissioner Abbott Washburn Concurring in Part and Dissenting in Part

Summary

I am concurring is seeking public comment on the actions described in the Notice with regard to ascertainment and non-entertainment programming. I am dissenting with regard to the proposed action on commercialization. I also offer an alternative proposal on ascertainment.

Ascertainment

The Notice asks questions of the public about the proposed recission of all ascertainment requirements for AM and FM licenses. While I can concur in going out with questions on this matter, I doubt that in the long run it would be in the public interest to abandon ascertainment altogether. In recent years the ascertainment process has contributed to the development of a healthy "dialogue" between broadcasters and public groups and leaders at the local level. It has proved useful to licensees, the Commission, and the public alike. To abandon it completely now would be a waste. Admittedly, however, it has become too detailed, complicated, and time-consuming a process.

Accordingly, I propose an alternative course of action wherein the present ascertainment requirements would be greatly reduced and simplified, while at the same time stating specifically what the Commission requires. Under such a change, for example, the general public survey would be eliminated altogether and the requirements for the community leader survey simplified.

The Notice indicates that even though the 6% FM guideline and the 8% AM guideline for informational programming would be abandoned, the Commission still would expect broadcasters to provide such programming to meet listeners' preferences. *Therefore, some form of ascertainment would be needed.* The simplified procedure, suggested above, should meet this requirement. I hope that respondents will address this alternative approach.

Guidelines for Informational Programming

The Notice seeks comments on a proposal to abandon the 6% FM guideline and 8% AM guideline for informational programming. While I can concur in seeking such comments, I am concerned that doing away with these guidelines could generate serious problems for the Commission. Without them, for example, the Commission would be seriously hampered in the comparative hearing process and in the petition-to-deny process—a "vexing problem," as the Notice states in paragraph 261. After decades of weighing these public-service considerations in assessing licensee performance, *not* looking at these factors now would be a dramatic about-face. The Commission would unquestionably face strong legal challenges in the courts, especially since numerous public-interest groups have found the guidelines to be important benchmarks for gauging broadcasters' efforts. Both they and the broadcasters themselves would be left in uncertainty as to what standards the FCC *would* employ with respect to news and public affairs programming.

The litigation and uncertainty could be lengthy. Would the deregulatory benefits be offsetting? I think not. Most broadcasters now carry informational programming in excess of the percentages in the guidelines. Their elimination, therefore, would not represent significant "relief" to the industry.[1]

I will concur in seeking comments on this proposal, but with serious doubts as to its usefulness.

Action in the Event of "Failure of the Market"

The Notice states that while the Commission will no longer examine percentages of news and public affairs programming, it "will not completely absent itself from consideration of these factors." It will expect adequate performance market-by-market. In the event of "failure of the market," the Commission will "take whatever actions are required by the public interest to correct the situation" (Para. 260). Comments are sought as to what form of action this might be.

On the one hand we seem to be abandoning these time-honored measurements of the broadcasters' public-service performance. On the other hand we insist "we intend to see that the public interest is served" (Para. 242). How will we assess "failure of the market" in this area of informational programming? By what standards will the Commission judge such failure? Does the Commission have the legal authority to examine and regulate markets? How will individual stations know what is expected of them? How will public-interest groups be able to proceed?

Esther Peterson, Consumer Advisor to the President, phrased it well in testimony before the House Communications Subcommittee on July 10, 1979: "The goal of informing the public is best served when all stations are obligated to contribute to its advancement." Otherwise, she pointed out, "minority and other citizens groups would lose their ability to negotiate with broadcasters about programming that addresses their interests."

In this proposed move the Commission gives the impression of seeking to delete informational programming requirements completely. In actuality, however, it would be jettisoning clear guidelines for news and public affairs, and substituting in their place "further actions" of an undefined nature. This somewhat equivocal posture of the Notice gives rise to the difficulties.

If the undefined "further actions" are to become specific later—fashioned on the responses to the Notice—it would seem

[1] I am also troubled by the evidence that public affairs programming could be short-changed. Paragraph 184 on page 69 states:

"The evidence that we have presented strongly suggests that on a marketwide basis there will be a significant amount of news programming in both large and small markets. There is no evidence of similar consumer demand for public affairs programming."

And, again, paragraph 189 on page 70 reports that while there would continue to be a substantial amount of local news programming, "There is no similar evidence for local public affairs programming."

Absent government guidelines, therefore, the Notice seems to be saying that public affairs programming would likely go by the boards. (Unlike news, of course, it is not usually profitable). How can this be reconciled with the first prong of the statutory Fairness Doctrine, which requires coverage of major issues in the community?

better to withold judgment on this course of action until all the comments are in.

Commercialization

The Commission over the years has encouraged self-regulation in this area. Examples of self-regulation are the NAB Radio Code limit of 18 minutes of commercial matter per hour, and the NAB Television Code and INTV Code limit of 9½ minutes of commercial matter per hour for weekend children's television programs.

The fact that the FCC has endorsed these self-restrictions and made them its own policies has resulted in greater adherence to them by broadcasters. (It has also helped to gradually bring the commercialization levels down.) If we should now drop our interest in them, the trend would be in the opposite direction. The percentage of licensees adhering to them would decline. It can be argued, as the Notice does, that the marketplace will take care of this, that the public will avoid stations that overcommercialize. But there is not much evidence to support this contention. In some markets the station or stations choosing to exceed the 18-minutes-per-hour limit could well pull along some of the others, who would feel that they, too, had to do so in order to be competitive. The public in these markets would then be subjected to higher levels of commercialization.

The fact is, I am convinced, that the public *expects* the FCC to involve itself in commercialization. It *expects* us to indicate reasonable limits beyond which a broadcaster is overcommercializing and imposing an undue burden on the listening and viewing audiences.

So I have trouble with any proposed action by the Commission that diminishes our consideration of, and interest in, the matter of overcommercialization. On this point, therefore, I must dissent.

Statement of Commissioner Joseph R. Fogarty

Concurring in Part; Dissenting in Part

In Re: Deregulation of Radio

I concur in the *Notice of Inquiry and Proposed Rule Making* to the extent that it seeks full public comment on the deregulatory issues and options set forth, but I dissent to the declaration of a Commission preference at this time in favor of completely abandoning our regulation concerning ascertainment, nonentertainment programming, and commercialization.

This *Notice* is premised on changes in the radio industry, principally the great increase in the number of radio stations since the commencement of regulation in 1934, and on "neoclassical" economic theory which contends that consumer welfare is best served by the free, unrestrained interplay of market forces of supply and demand. The *Notice* posits the fundamental issue of whether there can be greater Commission reliance on marketplace forces and commercial judgments in ensuring that radio will serve the public interest in programming diversity, including service to significant minority interests and tastes. With respect to our current nonentertainment programming guidelines, the *Notice* develops the economic argument that absent regulation the radio marketplace will still provide listeners with adequate news programming. Although the *Notice* concedes that "public affairs" programs would decline under deregulation, it views their potential loss as acceptable, arguing that this programming is non-economic and that the discerned industry practice of "graveyarding" public affairs indicates that listeners do not value such programs. The *Notice* argues a case for the deletion of all ascertainment requirements as redundant of normal business judgments in a competitive radio marketplace and as imposing unnecessary regulatory burdens. Current guidelines on overcommercialization are considered similarly unnecessary in a competitive marketplace.

To consider carefully and to seek full public comment on these issues and arguments is proper and appropriate. We are under no mandate to prefer particular regulation simply for its own sake. Indeed, we have a continuing responsibility to reassess the costs and benefits of our regulatory means and ends to ensure that the public interest is being served in fact as well as in theory. Whether a deregulated radio marketplace can be relied upon to meet the public interest more effectively than regulation is a matter of debate before Congress and this Commission. This Notice hopefully will provide the Commission with a record for possible legislative recommendations and possible agency action as well.

While I concur in the commencement of this proceeding, I strongly believe that the *Notice* only states the fundamental questions; it does not answer them. The *Notice* raises difficult and complex legal and policy issues whose resolution is at this time far from clear. It is therefore premature for any categorical statement of a preferred course of Commission action.

At the outset of this inquiry, it bears emphasizing that because the Commission is proposing changes in not only its regulation but also in its interpretation of its legislative charter, the Communications Act of 1934, as amended, strict adherence to the principles of reasoned agency decisionmaking is essential. While the Commission's exercise of its quasi-legislative rulemaking power is entitled to a wide degree of deference, our discretion is not unbounded. Our rulemaking actions must be consistent with the standards of the Administrative Procedure Act which require the setting aside of any "agency action, findings, and conclusions" which are "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law," [1] or "in excess of statutory jurisdiction, authority, or limitations, or short of statutory right." [2] The stringency of review under these standards depends in a given case "upon analysis of a number of factors, including the intent of Congress as expressed in the relevant statutes, particularly the agency's enabling statute; the needs, expertise, and impartiality of the agency as regards the issue presented; and the ability of the court effectively to evaluate the questions posed." [3] Beyond these general principles, court decisions have established that more exacting scrutiny will be called for when for some reason the presumption of regularity usually accorded agency decision making is rebutted. Such rebuttal may be implicated when an agency departs from its consistent and longstanding precedents or policies. As the Court of Appeals for the Second Circuit has stated:

* * * changes in policy must be rationally and explicitly justified in order to assure "that the standard is being changed and not ignored, and that [the agency] is faithful and not indifferent to the rule of law." Although an agency must be given flexibility to reexamine and reinterpret its previous holdings, it must clearly indicate and explain its action so as to enable completion of the task of judicial review. [citation omitted.] There must be a thorough and comprehensible statement of the reasons for the decision * * *. [citation omitted.] [4]

I have set out these principles of reasoned decision making at some length because of the conviction that *how* we arrive at our ultimate decision on the issues presented in this *Notice* is as critically important as the substantive result reached. Any deregulation we adopt will be of no avail to either public or industry if it is not done right. The judicial teachings mean that as a minimum requirement, the Commission must demonstrate that any contemplated deregulation of radio will continue to meet and serve the public interest goals and purposes of our existing regulation; or, in the alternative, we must show why the public interest will be better served by modifying or abandoning those goals and purposes, if that is to be the intent of effect of any deregulatory action. The Commission must also square any deregulation with its legislative mandate, the Communications Act of 1934, as amended, and the intent of Congress in its enactment.

While I do agree with the *Notice* that the economic concepts of competition and "consumer well-being" are essential elements of the "public interest" standard established by the Act, they are but component parts of the public interest and not its whole. Other values in addition to "economic" satisfaction are implicated: "It is the right of the public to receive suitable access to social, political, esthetic, moral, and other ideas and experiences which is crucial here." [5] In interpreting its statutory mandate, the Commission has long recognized that "the paramount and controlling consideration is the relationship between the American system of broadcasting carried on through a large number of private licensees upon whom devolves the responsibility for the selection and presentation of program material, and the congressional mandate that this licensee responsibility is to be exercised in the interests of, and as a trustee for the public at

[1] 5 U.S.C. 706(2)(A).

[2] 5 U.S.C. 706(2)(C).

[3] *Natural Resources Defense Council, Inc.* v. *SEC.* —F.2d—, No. 77-1761 (D.C. Cir., April 20, 1979), slip op. at 34.

[4] *Office of Communication of the United Church of Christ* v. *FCC*, 560 F.2d 529, 532 (2d Cir. 1977).

[5] *Red Lion Broadcasting Co.* v. *FCC*, 395 U.S. 367, 390 (1969).

large which retains ultimate control over the channels of radio and television communications." [6] The Commission's regulatory responsibility in the broadcast field "essentially involves the maintenance of a balance between the preservation of a free competitive broadcast system, on the one hand, and the reasonable restriction of that freedom inherent in the public interest standard provided in the Communications Act, on the other." [7 8]

In meeting this regulatory responsibility of balancing free competition with public interest obligation, the Commission has left broadcasting's development and presentation of entertainment programming largely to marketplace competition.[9] However, long-standing Commission policy has recognized that competitive forces alone may not afford the public suitable access to news and other informational programming; the Commission has considered it a "necessity for licensees to devote a reasonable percentage of their broadcst time to the presentation of news and programs devoted to the consideration and discussion of public issues of interest in the community served by the particular station."[10] The fundamental concerns underlying both the ascertainment and nonentertainment programming requirements have been consistently stated:

It is axiomatic that one of the most vital questions of mass communication in a democracy is the development of an informed public opinion through the public dissemination of news and ideas concerning the vital issues of the day.[11]

[W]e have allocated a very large share of the electromagnetic spectrum to broadcasting chiefly because of our belief that this medium can make a great contribution to an informed public opinion.[12]

It is unclear to me whether it is the position of the *Notice* that an unregulated radio marketplace will continue to meet these public interest goals and policies or that these goals and policies are now to be considered irrelevant or superseded by the somewhat illusive concept of "consumer welfare." At several points the *Notice* appears to concede that because of the absence of a pricing mechanism directly linking consumer demand with programming supply, there may be significant distortions in the radio marketplace that would preclude the continued availability of diverse information programming.[13] Yet, the *Notice* relies confidently on general economic theory in repeatedly concluding that any such distortions should be minimal and that in any event the marketplace is far more competent than the Commission to make consumer welfare judgments in this area. In this regard, the *Notice* seems to say that because the benefits of existing regulation are hard to identify and quantify empirically, the burden should be on regulation to justify itself, even though it is conceded that the benefits of future deregulation are equally elusive. Here, there is a pervasive and troubling circularity in much, if not all, of the proffered economic justification for complete deregulation: i.e., the marketplace will best serve the public interest because the public interest is best served by the marketplace; or otherwise stated, whatever programming is produced by the marketplace is by definition in the public interest.[14]

I believe the applicability and efficacy of this neoclassical economic model and theory in today's radio industry deserves a fair hearing in this proceeding. But, the Commission's existing statutory mandate, if not also intellectual honesty and procedural fairness, compels a measure of judicious circumspection before we so confidently and completely abandon our minimum of public interest regulation in favor of the uncharted vicissitudes of the marketplace.

The *Notice* relies on the existence of all-news or news-oriented stations in radio markets with 16 or more stations and on data indicating that news programming exceeds Commission guidelines in smaller markets to suggest that absent regulation there will be no lack of availability of such programming. While this analysis is a basis for some optimism, it must be remembered that these are statistics generated in a *regulated not a deregulated* environment; they predict but do not speak with certainty. The *Notice* concedes that news is high-cost programming. It is my impression that many, if not most, radio licensees comply with our current guidelines by subscribing to one or more of the news wire services or networks. Having made the financial commitment to such services or networks, these stations have an obvious incentive to use and broadcast this news material. Whether licensees will continue their present levels of news programming when given the option and the financial incentive to drop news in favor of less costly programming is far from clear. Since there is evidence (the Magid/AP study cited at paragraphs 170–71) that a majority of the listening public values (i.e., "pays attention to") news programming when it comes on the radio but only a minority choose a station for its news, a potential "marketplace failure" may be indicated. There is also a troubling issue in the *Notice's* implication that in larger markets, the public interest (or "consumer welfare") would continue to be served where all but one station ceased any significant news effort, provided the one remaining station was all-news or "news oriented." To square such an extreme degree of deference to marketplace competition with the public interest licensing

[6] *Editorializing by Broadcast Licensees,* 13 FCC 1246, 1247 (1949).

[7] *En Banc Programming Inquiry,* 44 FCC 2303, 2309 (1970).

[8] The section of the *Notice* treating "Historical Perspective" implies the Congress in its 1927 and 1934 enactments of broadcast legislation was primarily concerned with the incipient RCA radio monopoly. Although not entirely clear, the further implication appears intended that since the RCA monopoly has long since passed away, there is no longer any continuing statutory mandate for public interest regulation of radio. This revisionist history is conspicuously devoid of any supporting citation to the legislative record of the 1927 and 1934 Acts. Secretary of Commerce Hoover's often-cited "warning," quoted at paragraph 11 of the *Notice,* is on its face of broader import and effect than any such restrictive interpretation. It squares better with the long-held view that Congress considered the airwaves a natural resource to be held in trust for all the people of the United States and intended that broadcasters who receive their radio frequencies free take them as fiduciaries for the public whose interests they are licensed to serve. To quote Hoover, broadcasting was "not to be considered as merely a business carried on for private gain * * *"

The *Notice* also contains several recurring references to public, federally-financed broadcasting, particularly National Public Radio, in contexts which suggest that the creation and development of noncommercial radio may provide a basis for abandoning the public interest regulations of commercial radio. See paragraphs 56, 90, 133, 144 n. 155, and 156–59. Again, the *Notice* offers no citation to the legislative history of the public broradcasting statutes in support of this novel interpretation. There is, however, plain language to the contrary. In its Report of the legislation that created public broadcasting, the Public Broadcasting Act of 1967, the Senate Committee on Commerce stated:

The programming of these [public broadcasting] stations should not only be supplementary to but competitive with commercial broadcasting services. This competition will benefit both types of service.

In this connection your committee wishes to make crystal clear that the enactment of this legislation and the growth of noncommercial broadcasting services, will in no way relieve commercial broadcasters of their responsibilities to present public affairs and public service programs, and in general to program their stations in the public interest. S. REP. NO. 222, 90th Cong., 1st Sess. 6 (1967).

Similarly, the corresponding Report of the House Committee on Interstate and Foreign Commerce stated that "The program support provided by Title II of the Bill will, among other things, enable the noncommercial educational broadcast stations to provide *supplementary* analysis of the meaning of events already covered by commercial newscasts." H.R. REP. NO. 572, 90th Cong., 1st Sess. 10 (1967) (Emphasis added). The legislative record of subsequent amendments to the public broadcasting charter discloses no contrary views.

The point of this digression is that the equating of "historical perspective" and legislative intent is a slippery and perilous enterprise.

[9] Although the subject of continuing Commission disputation, the Commission's statutory responsibility to pass upon voluntary assignments of radio licenses has been construed to require that the Commission consider whether the proposed abandonment of a distinctive radio programming format is in the public interest; where a significant segment of the listening public opposes the assignment in protest of the loss of such a format and presents substantial factual allegations that the format is both unique and financially viable, the Commission will be required to hold a hearing. *WNCN Listeners Guild v. FCC, F.2d* , No. 76–1692 (D.C. Cir., *en banc,* decided June 29, 1979); see also Dissenting Statement of Commissioner Joseph R. Fogarty in re: Decision to Seek Supreme Court Review of *WNCN Listeners Guild v. FCC,* FCC News Release, Mimeo No. 20773 (August 24, 1979).

[10] *Editorializing by Broadcast Licensees,* 13FCC at 1249.

[11] *Id.*

[12] *Fairness Report,* 39 Fed. Reg. 26372, 26375, 48 FCC 2d 1, 10 (1974).

[13] See, e.g., paragraph 136: "Certain demographic groups . . . particularly the elderly, may not be valued highly by advertisers and thereby may have less impact on programming than they would under a traditional market arrangement;" and paragraph 144: Researchers "agree that advertiser-supported broadcast markets will not respond perfectly to consumer wants, primarily due to the failure to ascertain intensity of demand. * * * Most likely to be omitted are (1) programming for which there is a small audience that highly values the programming (but cannot register that preference due to the lack of a pricing mechanism) and (2) high cost programming."

[14] This observation recalls the remark of economist John Kenneth Galbraith that "Economics has been not a science but a conservatively useful system of belief defending that belief as a science."

standard of the Act would be an exceedingly difficult task.

With respect to the *Notice's* discussion of public affairs programming, I find it somewhat curious and ironic that the current industry practice of "graveyarding" such programs is cited as a ground for sanctioning their abandonment. While public affairs programs may be "non-economic" (i.e., not as profitable as, say, automated disco) in the mass audience-oriented radio marketplace, I would prefer to see some attempt at discerning whether such programs appeal to significant minority audiences, thereby indicating a possible "marketplace failure," before blessing their demise. More importantly, however, I have considerable difficulty reconciling a decline in public affairs programming with the commitment of the Commission and the Congress to the continued importance of the fairness doctrine. As recently as 1974, the Commission emphasized that " 'we regard strict adherence to the fairness doctrine'—including the affirmative obligation to provide coverage of issues of public importance—'as the single most important requirement of operation in the public interest—the "sine qua non" for grant of a renewal of license.' " [15] The *Notice* proposes no change in our fairness doctrine policies or commitment, recognizing that its obligations are a statutory requirement.[16] How the Commission can approve the abandonment of public affairs programming by radio licensees consistent with these policies and commitment warrants explanation.

More fundamentally, I do not believe that the Commission may lawfully abrogate its existing regulation *solely* on the basis of untested theory which leaves the public interest in radio communication so totally to the marketplace. As the Court of Appeals for the D.C. Circuit has repeatedly advised this Commission:

"* * * radio channels are priceless properties in limited supply, owned by all of the people but for the use of which the licensees pay nothing. If the marketplace *alone* is to determine programming format, then different tastes among the totality of the owners may go ungratified. Congress, having made the essential decision to license at no charge for private operation as distinct from putting the channels up for bids, can hardly be thought to have had so limited a concept of the aims of regulation. In any event, the language of the Act, by its terms and as read by the Supreme Court, is to the contrary." [17]

I recognize that the theory and arguments advanced in the *Notice* are to a large extent imponderables in the paper context of an administrative rulemaking proceeding and that their merit as a public interest substitute for existing regulation is necessarily dependent on their application in the real world of the broadcast radio marketplace. For this reason, I would be prepared to test the *Notice's* assumptions and predictions in a marketplace experiment with deregulation. What I am not prepared to do at this juncture is simply to declare a deregulation victory in the name of neoclassical economic theory and walk away from the radio marketplace before the battle begins. A more reliable and secure basis for deregulation is required.

In this connection, I see that the *Notice* states that "If we found that the marketplace had failed to serve the public adequately, we would have to be prepared to take appropriate action to remedy the situation." [18] However, the *Notice* is all too silent as to how we will know whether or not the marketplace is failing (i.e., the question of data and evaluation standards), and what regulatory remedies for failure would be appropriate. Most troubling in this regard is the proposed elimination of the program log requirements for broadcast radio stations. Apparently, the *Notice* would provide neither the Commission nor the public with the data base and ongoing record necessary to determine whether deregulation is serving the public in fact as well as in theory. The *Notice* states the expectation that no marketplace failure will occur. However, given the proposed evidentiary void, this confident statement hardly instills confidence.

I understand the *Notice's* hesitancy to conduct a marketplace experiment in view of the so-called "Hawthorne effect" which holds that where the subjects of an experiment have a strong interest in achieving a particular outcome, the results may be subject to considerable question. However, this hesitancy cannot justify a total failure to provide any means or basis for assessing the success or failure of the proposed deregulation. The apparent reluctance of the *Notice* to grapple with this dificiency suggests less than full confidence in the results, as opposed to the theory of deregulation. If we are not prepared to undertake a marketplace experiment, then the burden is clearly on the Commission—not merely on public complainants—to monitor the results of deregulation systematically and to report to the public on the record thereby developed. Without these safeguards, the real basis for deregulation will be perceived as nothing more than the less than satisfactory principle that whatever the marketplace produces is a priori in the public interest.

One final matter merits particular attention and comment. The *Notice* indicates that although ascertainment, nonentertainment programming, and commercialization issues would be generally eliminated in comparative hearings, it states that applicants would still be compared on the "other criteria" discussed in the 1965 *Policy Statement*, including "diversification, character, and spectrum efficiency." The *Notice* further suggests that if a challenger were better qualified under these criteria, then upon the incumbent's request the Commission might consider the incumbent's nonentertainment programming or its entertainment programming to determine whether its past service nonetheless entitled it to prevail; and in that case the challenger would be permitted to introduce its own program proposals for comparative evaluation.

This aspect of the *Notice* raises serious and difficult problems. First, it is far from clear how this approach would square with the "best practicable service" creterion mandated by the Communications Act.[19] In this connection, the Act specifically provides for the filing of competing applications both for new facilities and against the renewal applications of incumbent licensees,[20] and the Commission must give such applications a comparative hearing according to rational, defined standards.[21] The *Notice* is vague to silent on how the Commission can determine comparative hearings under marketplace deregulation without initial and direct reference to the critical element of program service. As Mr. Justice Frankfurter's opinion for the Court in *National Broadcasting Co.* v. *United States* states:

* * * The Act does not restrict the Commission merely to supervision of the traffic. It puts upon the Commission the burden of determining the composition of that traffic.[22]

It is also unclear how, absent the articulation of programming performance standards, the Commission could determine that an incumbent facing a challenger with diversification advangages should nonetheless prevail because of a "meritorious" past broadcast record. Some regulatory standard would have to give content and substance to this elusive adjective in the equally elusive context of a deregulated radio marketplace. At this point, the *Notice* begins to look like deregulation for non-multiple, management-integrated radio station licensees, and dangerous uncertainty for everyone else.

The Act also specifies that a broadcast radio license conveys no right of ownership and no interest beyond the prescribed license term.[23] The conceptual difficulties which crop up in the context of comparative hearings indicate that our consideration of radio marketplace deregulation must confront the contention that the *Notice* may be proposing to do what the Act forbids: create a vested property right in the channels of many, if not all, incumbent radio broadcast licensees. *De facto* private ownership comports with neoclassical economic theory applied to broadcasting; however, it does not accord with the clear statutory mandate and regulatory structure enacted by the Congress.

Separate Statement of Commissioner Tyrone Brown

Re: Notice of Inquiry and Proposed Rulemaking *in the Matter of Deregulation of Radio*

I voted for issuance of this Notice of Proposed Rulemaking/Notice of Inquiry

[15] *Fairness Report*, 39 Fed. Reg. at 26375, 48 FCC 2D at 10, citing *Committee for the Fair Broadcasting of Controversial Issues*, 25 FCC 2d 283, 292 (1970).

[16] See paragraph 192 and n. 178.

[17] *WNCN Listeners Guild*, supra n. 9, slip op. 40–41 (Emphasis added), citing *Citizens Committee to Save WEFM v. FCC*, 506 F. 2d 246, 268 n. 34 (D.C. Cir. 1974) (*en banc*).

[18] Paragraph 241.

[19] The Supreme Court has held that the public interest licensing standard encompasses " '* * * the ability of the licensee to render the best practicable service to the community reached by his broadcasts.' " *National Broadcasting Co.* v. *United States*, 319 U.S. 190, 216 (1942), citing *FCC* v. *Sanders Radio Station*, 309 U.S. 470, 475 (1940).

[20] 47 U.S.C. 309(e).

[21] *Ashbacker Radio Corp.* v. *FCC*, 326 U.S. 327 (1945); *Citizen Communications Center* v. *FCC* 447 F.2d 1201 (D.C. Cir. 1971).

[22] 319 U.S. 190, 215–216 (1943).

[23] 47 U.S.C. 301, 307(d).

because I believe a comprehensive reexamination of this Commission's approach to regulation of commercial radio broadcasting is overdue. A host of considerations require such a searching inquiry.

The number of commercial radio outlets has increased almost 15-fold since enactment of the 1934 Communications Act, and television has replaced radio as the principal information medium. As a result, program specialization in radio has developed to a greater degree than was envisioned in the early years. Moreover, in addition to 8,653 commercial radio stations, there are today nearly 1,000 noncommercial educational stations that did not exist in 1934. Industry spokesmen and representatives of various listener groups contend (though the differing reasons) that, notwithstanding the sizeable portion of our resources that go into regulating radio, our effort falls far short of achieving public interest objectives. The Congress recently responded to these expressions of dissatisfaction by considering legislative proposals which would substantially alter the existing regulatory regime. Under these circumstances, a fresh look certainly is in order. For this reason, I wholeheartedly endorse the promise in this Notice that the proceeding we open today is but the first part of a review of all of our nontechnical radio rules, regulations and policies.

I also applaud the Commission's decision to extend this review to all markets and not merely to large markets as originally suggested. If our regulations impose any unnecessary burdens at all, they fall most heavily on small market broadcasters whose time and resources are often limited.

Finally, I am pleased that the Commission is prepared to take action following the appropriate notice and comment procedures without requiring a period of experimentation. As I have indicated elsewhere,[1] I believe an experiment would not serve any valid purpose. Broadcasters would be well aware that they are under a microspcope and that on their conduct rests the fate of "radio deregulation."

I wish to emphasize that my vote in favor of issuance of the Notice indicates no preference—tentative or otherwise—for the so-called "Course That We Propose To Take" discussed in the Notice. It was clear during the Commission meeting on this matter that a majority could not be marshalled to vote, even tentatively, for elimination of all nonentertainment programming, ascertainment, commercialization and logkeeping requirements. Thus, the "proposed" course of action outlined in the Notice should be considered nothing more than the most far-reaching deregulatory option suggested by the record as it now stands.

I currently favor substantial deregulation. However, as indicated bleow, I am inclined toward something less than complete regulatory forebearance on nonentertainment programming and ascertainment. In any event, whatever course the Commission ultimately adopts, I hope it is one that eliminates unnecessary paperwork, provides as much certainty as possible, and maintains the public interest objectives upon which the communications Act rests.

1. *Scope of this Proceeding.* The term "deregulation," fashionable though it has become, is somewhat of a misnomer for the options that will be available to the Commission at the close of this proceeding. Before the Commission can grant an initial or renewal radio broadcast license, we are required by statute to determine whether such a grant will serve the public interest, convenience and necessity. The public interest standard is a part of our statutory mandate, and we cannot eliminate or ignore it. Thus, as the Notice emphasizes, there is no intent in this proceeding to deregulate radio in the sense of eliminating the public interest standard.

Nor, for purposes of this proceeding, is there any controversy over the underlying specific public interest objectives toward which our existing rules and policies are directed. Although some may question those objectives in other contexts, the Commission currently holds to the view that the public interest requires (1) that regular informational programming be available to radio listeners, (2) that broadcast management stay in touch with the community so it is aware of local needs and interests, (3) that radio not become a wall-to-wall advertising medium, and (4) that radio licensees maintain records to document fulfillment of their public interest obligations. Undoubtedly, we will receive comments that these objectives are wrongheaded. I do not propose to consider such comments. We are here drawing into question not the underlying public interest objectives, but only the means of achieving those objectives.

A further point of clarification is in order. This proceeding is limited to nonentertainment programming. We are not here concerned with Commission regulation of entertainment formats *per se*, a question now before the courts. *WNCN Listeners Guild* v. *FCC*, Slip Op. No. 76-1692 (D.C. Cir. June 20, 1979). Specialized entertainment formats to provide specialized information programming to their targeted audiences.

2. *Why Consideration of Deregulation at All?*

All regulatory programs cost money. They impose costs on business (ultimately borne by the consuming public, in radio's case in the form of higher prices for advertised products) and direct costs on all taxpayers. For fiscal year 1978, we estimate that the FCC's portion of the direct costs of governmental oversight of radio broadcasting was $13.3 million, or just under 20 percent of the total budget of this agency. These public expenditures are certainly justified if the purposes of the regulatory program they foster could be achieved only by regulation. However, if (and to the extent that) our regulations do not affect the conduct of radio broadcasters—motivating them to provide services they would not otherwise provide—we are wasting the taxpayer's money. Under such circumstances, we would also be imposing unnecessary and far greater indirect costs on consumers through the paperwork requirements that broadcasters currently must meet. For this reason, regulatory agencies should periodically review regulatory requirements to determine whether they in fact advance public policy goals.

In this instance, economic analysis conducted by our Staff and empirical evidence we have gathered to date, arguably indicate that competition for listeners in the radio marketplace is achieving the public interest objectives of our nonentertainment programming, ascertainment and commercialization rules and policies.[2] Given the economic and other data described in the Notice, I believe we are obligated to ask whether greater regulatory forbearance on radio programming is the proper course.

3. *Economic Analysis.* The economic analysis set forth in the Notice suggests that, along with other factors, the increase in the number of radio stations—by 2,000 in the past ten years—has resulted in marketplace competition for listeners that effectuates public interest objectives at least as well as our existing rules and policies. Specifically, the data indicates that radio stations generally broadcast substantially more informational programming than our guidelines require and fewer commerical minutes than the guidelines permit. These preliminary findings are central to the proposal to eliminate nonentertainment programming and commericalization guidelines. Undoutedly, they will be subjected to careful scrutiny by the commenting parties.

At the outset, I recognize that the radio marketplace is not a perfect one. Although there certainly are many marginal operations, the industry on the whole appears to enjoy handsome profits—in excess of what would be expected under circumstances approaching ideal competition.[3]

I do not believe this imperfection in the radio market, to the extent it exists, is a basis for rejecting any of the options described in the Notice. If the market, imperfect though it may be, would achieve all public interest objectives on its own, then there is no need for regulation. However, the existing profit condition of the industry carries a practical implication that is relevant to this proceeding. Considering the profitability of radio generally, the Commission probably

[1] Remarks of Commissioner Tyrone Brown Before The 17th Annual Southern California Broadcasters Association Public Service Workshop, Los Angeles, California, December 8, 1978 (FCC Mimeo No. 10397).

[2] Logkeeping (required by us for purposes of monitoring compliance) would no longer be justified as a governmental requirement if the other programming requirements are eliminated.

[3] This Commission's past allocation policies, resulting in the licensing of fewer stations in some markets than today would be optimal economically, probably constitute the principal reason why many radio broadcasters enjoy exceptional profits. This is not intended as a criticism of past allocation policies. Technical limitations (including perceived limits on the useable portion of the electromagnetic spectrum and the needs of other spectrum users) have often taken precedence over economic considerations in the Commission's spectrum allocation decisions. Moreover, an allocation policy that appears optimal in the infancy of an industry may be less than optimal at a later date, depending on the demand for the product—here the ability to reach large numbers of consumers with advertising.

could not justify deregulation solely (or even substantially) as a step taken to ameliorate burdensome regulatory costs borne by the industry. Such a rationale would not ring true at a time when prospective owners are virtually standing in line to acquire radio facilities. Thus, I repeat, deregulation must be defended, if at all, on the basis that existing rules do not make a difference and therefore are an unnecessay burden to taxpayers and consumers.

There is another characteristic of the radio marketplace that makes it imperfect. Radio broadcasters compete vigorously for the largest possible audience. At the same time, they also compete for advertising revenues. As our Notice points out, in a sense the listener is not the consumer of radio but the product which broadcasters sell to advertisers. In other words, in radio broadcasting, true consumer (listener) sovereignty does not exist insofar as advertiser wants do not correspond with listener wants. Given that fact, certainly there are circumstances under which it is appropriate for the Commission to intervene on the side of the listener, and certainly we have done so in the past. Our economic analysis indicates, however, that the intervention we currently engage in—through the programming and commercialization guidelines and the ascertainment requirements—does not generally contribute to listener sovereignty beyond that provided by market forces. This is the proposition at the heart of the economic analysis which I hope will be thoroughly tested through adversary comment in this proceeding.

4. *Policy and Legal Considerations.* The most far-reaching option described in the Notice proposes regulatory oversight of radio broadcast markets rather than of individual broadcasters. This approach also proposes that the Commission for the first time explicitly announce that it will not (except as required under the Fairness Doctrine) require provisions of particular broadcast services for listener groups not large enough to attract their preferred program services in the marketplace. In my judgment, the proposal to switch to broadcast market regulation is the most fundamental change envisioned by the Notice, and the proposal to limit regulatory concern to economically significant listener groups is the most controversial.

It bears repeating that the Commission's regulatory approach cannot contravene the terms or intent of the Communications Act. That statute prescribes a scheme for periodic licensing of individual stations, with individual station accountability. It may be that a shift from individual to marketwide responsibility on programming issues would constitute an impermissible departure from the terms or intent of the Communications Act. My current view, however, is that the statute accords the Commission sufficient discretion to shift to the marketwide approach with respect to programming if we determine, on the basis of a convincing record, that to do so will best serve the public interest. However, I consider this question to be a close one, and I hope the commenting parties will devote substantial attention to it.

During the Commission meeting that resulted in issuance of the Notice in this proceeding, Commissioner Jones asked whether our sole public interest concern in the areas under consideration is to assure that consumer "wants" are met. Commissioner Jones' question is a profound one. When the Notice repeatedly refers to the marketplace as maximizing consumer preferences, it is necessarily speaking of listener groups large enough to attract a market response to their program preferences. But what about listener groups that are not significant in this economic sense? Are they to be ignored?

As a policy matter, the Commission might conclude that economically insignificant groups are insignificant as a matter of communications policy because attempts to provide for them through regulation will not succeed or will not be worth the costs. At the moment, I cannot accept this conclusion on either ground.

Putting aside the issue whether the statute would permit us to totally ignore economically insignificant groups, our current regulatory approach is bottomed on the notion that groups and views that may not be attractive to advertisers should nonetheless have opportunities for access to the airwaves. Our current approach provides for such opportunity by requiring the broadcast of some nonentertainment programming.

I am particularly concerned about discussion of issues in their embryonic stage—before they reach the level of "controversial issues of public importance." Such discussions are to the Fairness Doctrine's "controversial" issues as a simple breaking and entering was to the resignation of a President. In the play of forces that determine what programming is to be aired, the proponents of views on nascent issues should have at least an opportunity to compete for access.

Moreover, as a practical matter, total elimination of nonentertainment programming guidelines and ascertainment requirements would not eliminate pressures for access to radio facilities. We might have to accommodate such pressures in other ways. For example, if we completely eschewed oversight of informational programming, I would expect to see many more complaints filed under Part One of the Fairness Doctrine.

All of this leads me to the most important question in this proceeding. Does competition exist in the radio marketplace to the extent that we can wash our hands of any involvement in nonentertainment programming? I fear that it does not, which is why I have offered a proposal which takes into account the desires of broadcasters for deregulation and for certainty but at the same time continues their public interest obligations.

5. *The Course I Propose to Take.* First, I have proposed elimination of Commission-enforced guidelines that have the effect of regulating the amount of time devoted to commercials on radio. I have made this proposal because I believe, given the variety of choices available to radio listeners, listener dissatisfaction with over-commercialization will be as effective a regulator of the amount of commercials run during the broadcast day as regulation by the FCC.

Second, I have proposed elimination of FCC-enforced guidelines looking toward specific percentages of news, public affairs and other nonentertainment programs. As a substitute for this category-by-category requirement, I have proposed that each radio broadcaster be required to devote a fixed minimum percentage of program time to *local* public service programming broadcast at reasonable times throughout the broadcast day.[4]

I believe local nonentertainment programming is the core of the public interest obligation in radio. But, if at all possible, I would leave it to each broadcaster to determine in the light of his particular format, how he would go about meeting that obligation. Thus, the flat local public service requirement I have proposed could be met through local news and public affairs programming, community bulletin boards, public service announcements or through other locally-produced nonentertainment programming demonstrably related to serving the local community's needs. Meeting that obligation would be a *sine qua non* for license renewal.

Third, I have proposed that the Commission eliminate the existing mechanistic approach to our ascertainment requirement. Ascertainment is intended to assure that broadcasters become familiar with the various elements in their communities so that they can direct their nonentertainment programming to the varying needs and interests of the community. However, largely at the behest of broadcasters, the Commission over the past 15 years has established a series of hoops for broadcasters to jump through to assure that they have "met" the basic ascertainment requirement. I would retain the substance of ascertainment so that broadcasters can take the results into account in meeting their local public service obligation. I would eliminate detailed formalistic requirements which have served only to generate mountains of paper and extended litigation. I would give broadcasters broad discretion—reviewable only for reasonableness—to determine how to go about meeting the substantive ascertainment requirement.

Finally, I have proposed elimination of FCC-required daily program logs to the extent such logkeeping no longer would be necessary to assure compliance with other requirements I have proposed to eliminate.

I have by no means arrived at a fixed position on the issues covered in the Notice. However, I believe my proposals have the advantage of eliminating much unnecessary paperwork and affording broadcasters the certainty and flexibility they are entitled to with regard to their public interest obligations. I also believe they do so without surrendering the public interest objectives of the Act.

Concurring Statement of Commissioner Anne P. Jones re Notice of Inquiry/Notice of Proposed Rule Making on Radio Deregulation

I agree with the general thrust of this notice and therefore concur in its issuance. I am not,

[4] This proposal is reflected in "Alternative 6" of the Notice's nonentertainment programming options.

however, prepared at this time to state a preference for any of the various options presented in it for changes in our rules, policies, or procedures on nonentertainment programming, ascertainment, commercialization, and program logs.

Whether one or the other of these options, some combination of them, or some approach to these matters we have not yet thought of is best is a decision which I believe will be better made after we have received comments on this notice, and I prefer to wait until then to make it.

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Friday
October 5, 1979

Part IV

Department of Energy

Federal Energy Regulatory Commission

Incremental Pricing

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 154, 201, 204, and 282

[Docket No. RM79-14; Order No. 49]

Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement the incremental pricing provisions of the Natural Gas Policy Act of 1978. Under the incremental pricing program, large industrial facilities which burn natural gas as a boiler fuel will be priced for that gas at a level equivalent to the price they would pay for fuel oil which they could burn as an alternative to natural gas. Those regulations provide the regulatory framework for the calculation and billing of incremental pricing surcharges to facilities subject to the incremental pricing program. The regulations also set forth the procedures by which an industrial facility may obtain an exemption from the program.

EFFECTIVE DATE: November 1, 1979, *provided that,* the provisions of 18 CFR 282.201-206 shall be effective October 15, 1979.

FOR FURTHER INFORMATION CONTACT:
Norman A. Pedersen, Office of Commissioner Hall, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8377.
Warren C. Edmunds, Office of Pipeline and Producer Regulation, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 275-4415.
Nancy E. Williams, Office of General Counsel, 825 North Capitol Street, N.E., Room 8100-F, Washington, D.C. 20426, (202) 357-8033.

Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978.

Issued: September 28, 1979.

I. Background

Title II of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95-621) requires that interstate pipelines and local distribution companies pass through certain portions of their natural gas acquisition costs to industrial users in the form of surcharges. These surcharges may not, however, raise the ultimate cost of gas to the user above the cost of the fuel oil which could be used as an alternative to natural gas.

The incremental pricing program is to be implemented in two phases. The only facilities affected during the first phase will be those using natural gas as fuel for large industrial boilers. Title II requires that the regulations implementing this first phase be promulgated by November 9, 1979.

During the second phase of the program, incremental pricing may be extended to a broader class of industrial users than those affected by the first stage. The NGPA sets May 9, 1980, as the date for the regulations implementing the second phase and establishes that those regulations will be subject to Congressional review and possible disapproval by either House.

Two rulemaking dockets were established to promulgate the regulations needed to implement the first phase of incremental pricing, Docket Nos. RM79-14 and RM79-21. A companion document to this final rule is being issued in Docket No. RM79-21.[1] The background of the proceeding in Docket No. RM79-21 is described in the final rule in that docket.

A Notice of Proposed Rulemaking and Opportunity for Written and Oral Presentations of Data, Views and Arguments in this docket was issued on June 5, 1979 (44 FR 33099, June 8, 1979) in order to propose regulations for the implementation of those provisions of Title II of the NGPA not encompassed by Docket No. RM79-21. These proposed regulations covered revisions to the Commission's historical method of calculating rate changes pursuant to purchased gas costs adjustment (PGA) clauses, the actual calculation and billing of incremental pricing surcharges, and the accounting provisions necessary for the implementation of the program. In addition, the proposed regulations set forth procedures to be utilized by facilities seeking to obtain exemptions from the incremental pricing program.

The approach set forth in the June 5th Notice for the calculation and billing of incremental pricing surcharges, the "surcharge mechanism," was developed after two informal conferences were held to give interested parties the opportunity to comment on preliminary proposals for the mechanism. Those conferences were held in February and April and were convened to discuss, respectively, a staff proposal issued January 12, 1979, (44 FR 6133, January 31, 1979) and several alternative proposals offered by various interested parties.

A public hearing on the June 5th proposal was held in Washington, D.C. on June 27, 1979. Nineteen interested parties presented comments at this hearing, including representatives of interstate pipelines, distribution companies, associations whose membership includes both pipeline companies and distribution companies, a consumer group and an industrial end-user group. A total of sixty-nine written comments were submitted in response to the June 5th Notice. The transcripts of the informal conferences, the June 27th hearing and all written comments submitted to the Secretary of the Commission in this docket have been made a part of the record in this proceeding. The Commission has reviewed all portions of this record in developing the final rule in this proceeding.

The regulations encompassed by this docket are lengthy and quite detailed. The comments submitted in this docket were generally excellent and very helpful. The discussion which follows seeks to fully explain how the regulations set forth below differ from those included in the June 5th proposal, as well as to respond to many of the suggestions that were raised in the comments submitted but which have not been incorporated in the final regulations.

[1] *Regulations Implementing Alternative Fuel Cost Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978,* Docket No. RM79-21, Final Rule issued on September 28, 1979. *See also* in Docket No. RM79-21, *Rule Exempting Industrial Boiler Fuel Facilities from Incremental Pricing Above the Price of No. 6 Fuel Oil,* issued on September 28, 1979.

II. Commission Jurisdiction

Title II of the NGPA significantly expands the jurisdiction of this Commission in comparison to the authority vested in the Commission pursuant to the Natural Gas Act. Title II brings within the purview of this Commission's jurisdiction for the first time all local distribution companies that receive supplies of natural gas from interstate pipelines. A definition of "local distribution company" has been added to the definitions section of the regulations below, § 282.103, in order to clarify exactly which companies are governed by the provisions of the regulations. The definition below differs from the definition of "local distribution company" set forth in the NGPA. However, this definition is adopted so that the one term, "local distribution company" may apply, for purposes of the incremental pricing regulations, to all companies, other than interstate pipelines, to which Congress intended Title II should be applicable. The intent of Congress in this regard is set forth in the Statement of Managers on the NGPA:

> The application of this rule is limited to boiler fuel facilities served by an interstate pipeline, and those served by a local distribution company that is served by an interstate pipeline. The term interstate pipeline is meant to include those pipelines which are subject to the jurisdiction of the Commission under the Natural Gas Act. "Hinshaw" pipelines, which are not subject to the Commission's jurisdiction under sec. 1(c) of the Natural Gas Act, are considered local distribution companies, for purposes of incremental pricing, to the extent that they are served by an interstate pipeline.[2]

Local distribution companies, as defined in § 282.103, as well as interstate pipeline companies, are required to comply with the regulations set forth below. The Commission anticipates that the Title II regulations will be enforced with equal emphasis as they apply to interstate pipelines and local distribution companies. In this regard, section 504 of the NGPA is noted. Under the provisions of section 504, violations of these regulations will be subject to civil and criminal penalties.

III. The Basic Mechanism: The "Reduced PGA" Approach

The basic approach for the calculation and billing of the incremental pricing surcharges has received significant and detailed discusion in this proceeding since the issuance of the initial staff proposal of January 12th. That proposal was structured so that incremental pricing surcharges would not be billed until 4 to 10 months after the actual incurrence of the costs to be passed through by way of surcharges. As a result of the February and April informal conferences, Commission staff determined to accept a recommendation made by the United Distribution Companies (UDC), Northern Natural Gas Company (Northern) and Natural Gas Pipeline Company of America (Natural) and to develop a mechanism which would allow for the recoupment of surcharges by suppliers at a time proximate to the time at which they must pay their own suppliers for gas deliveries which give rise to the surcharges.

The method suggested by UDC, Northern and Natural was to permit pipeline companies to estimate in advance their total gas acquisition costs and the portion of those costs which would ultimately be recovered by way of incremental pricing surcharges. The estimated surcharge recovery would be subtracted from the estimated total gas acquisition costs, and this "reduced" gas acquisition cost estimate would be recovered through the purchased gas costs adjustment (PGA) rate.

This reduced cost estimate would then form the basis of the PGA rate for all customers on a pipeline's system. Industrial customers included in the incremental pricing program would be billed on the basis of this reduced PGA rate, plus an incremental pricing surcharge.

An alternative to the "reduced PGA" approach was suggested by the Interstate Natural Gas Association of America (INGAA) at both the February and April informal conferences. This method would involve billing all customers on the basis of the normal PGA rate—which would reflect inclusion of all gas acquisition costs. Industrial customers included in the program would be billed an appropriate incremental pricing surcharge, while a corresponding credit would be extended to all other customers. The total of the credits would equal the amount recouped by way of surcharges.

The "INGAA method" received serious consideration by the Commission, but was not the approach eventually chosen and set forth in the June 5th proposed regulations. The Commission stated in the June 5th Notice that it believed that the "reduced PGA" approach would result in a "less burdensome regulatory program for all affected parties."

The Commission noted in the June 5th proposal, however, that it was continuing to consider the "INGAA method" and invited further comments as to whether that method should be adopted.

The comments submitted in response to the June 5th Notice were overwhelmingly in favor of the "reduced PGA" approach. On the basis of the record, the Commission adopts as a final rule the "reduced PGA" method of calculating and billing incremental pricing surcharges.

The "reduced PGA" method embodied in the final regulations will operate as follows. Each interstate pipeline will, prior to filing its revised PGA tariff sheet for an upcoming PGA period, estimate the total amount of gas acquisition costs it will incur during the upcoming PGA period. A pipeline will be permitted to take into account, when projecting its total gas acquisition costs for a coming period, increased costs anticipated due *to price increases permitted to* producers under the provisions of the NGPA. A pipeline will not, however, be permitted to take into account when making this projection any volume of supply which would not be attached to the system as of the date the new rate will take effect. Each pipeline will also estimate the portion of its projected total gas acquisition costs that will be "incremental costs" and thus subject to being passed through as incremental pricing surcharges.

The pipeline will then project the total maximum surcharge absorption capability (MSAC) of the non-exempt industrial boiler fuel facilities which will be served, directly or indirectly, by the pipeline.

The MSAC is the key element of the incremental surcharge passthrough mechanism. In simplest terms, it is the total difference between the cost of gas to a facility and the ceiling on incremental pricing which is applicable to the facility, i.e., the total amount of incremental cost the facility can absorb before its price of gas will rise above the applicable ceiling.

In order for a pipeline to develop its projected MSAC, each local distribution company will estimate the MSAC of each of its incrementally priced customers and report a total projected MSAC to its supplying pipeline. The projected MSAC of an individual industrial boiler fuel facility will be calculated in accord with the formula set forth in § 282.503 of the regulations. In those cases where a local distribution company is supplied by more than one pipeline, the total projected MSAC of the distribution company will be prorated among its suppliers in accord with a formula set forth in the regulations.

[2] H.R. Rep. No. 95-1752, 95th Cong., 2d Sess. 96 (1978).

Each supplying pipeline, in turn, will add the projected MSAC's reported to it by the distribution companies it serves and add thereto the total projected MSAC of all non-exempt industrial boiler fuel users it serves directly. This pipeline will then report its total projected MSAC to its supplying pipelines on a prorated basis.

This reporting will continue until the most "upstream" pipeline has received reports from all the interstate pipelines and local distribution companies served by it. After adding to the reported MSAC's the projected MSAC's of its own direct sale customers, this pipeline will compare its total projected MSAC to its total projected gas costs subject to surcharge passthrough for the coming PGA period. The pipeline will use the lesser amount to reduce its total estimated gas acquisition costs for the coming PGA period in order to derive a "reduced PGA" rate for the period.

The pipeline will file this "reduced PGA" rate with the Commission and use this rate for the following PGA period. As a result, there will be an immediate flow-through of the estimated benefits of incremental pricing to the residential and small commercial customers, since their gas rates will reflect the pipeline's "reduced PGA" rate.

Non-exempt industrial boiler fuel users will be billed on the basis of the "reduced PGA" rate. In addition, however, they will be billed an incremental pricing surcharge. The surcharges will be based on actual usage and actual alternative fuel price ceilings established for the month in which usage occurs.

In order to determine surcharges for both individual customers and sale-for-resale customers, actual MSAC's will be calculated for each industrial facility, local distribution company, and interstate pipeline. All information will be passed from resale customers to suppliers until the most "upstream" pipeline supplier has received reports from all customers on its system. It will then compare the total MSAC of its system for the past month to the total incremental gas acquisition costs it incurred during that month.

If the total incremental acquisition costs are less than the total MSAC, the "upstream" pipeline will bill surcharges on the basis of each customer's pro-rata share of the incremental gas costs. Each customer, in turn, will bill its customers a pro-rata share of the amount it has been surcharged, until each end-user is ultimately billed a surcharge.

If, however, the total incremental acquisition costs are greater than the total MSAC, the "upstream" pipeline will bill surcharges in the amount of the MSAC's. Each customer, in turn, will bill on the basis of its customers' MSAC's.

Any incremental acquisition costs which the "upstream" pipeline does not recover may be recovered in the following PGA period, just as under the present PGA system, since the unrecovered balance will be cleared to account 191, Unrecovered Purchased Gas Costs, following the billing of incremental pricing surcharges each month.

Incremental gas acquisition costs may be incurred directly by local distribution companies, as well as by interstate pipelines. To the extent that, due to the incremental pricing ceiling, those costs are not fully recovered through incremental pricing surcharges, they may be recovered in whatever manner is permitted by the appropriate State or local authority having jurisdiction.

IV. Billing Procedures

A. Meter Reading Cycles

In its June 5th Notice, the Commission proposed to require that the meters of incrementally priced industrial users be read on or about the 20th of each month. This aspect of the mechanism was intended to allow sufficient time for the communication of all information necessary for the calculation of surcharges between the end of the billing month and the normal date on which its was believed suppliers render bills to their industrial customers, i.e., the 10th of the following month. The 20th of the month billing period was based on representations made at the April conference with respect to the industry practice of billing industrial customers on a calendar month basis.

However, the majority of comments offered in response to the June 5th proposal criticized the proposed imposition of a uniform billing period ending on the 20th of the month. Many suppliers stated that industrial customers are billed on a cyclical basis in much the same manner as are high priority customers. Thus, to require the meters of all such customers to be read on the same day would disrupt present meter reading and billing practices.

In the course of analyzing the comments on this issue, Commission staff determined that the 20th of the month approach would effect another undesirable result. Under this method, the incremental pricing surcharges billed to many industrial customers for any given billing period would not reflect the acquisition costs incurred by their suppliers for the volumes delivered during the period for which the surcharge was calculated.

In order to avoid the imposition of one mandatory meter reading date and to address the problem identified by Commission staff, the following approach has been developed. The regulations set forth below treat a standard calendar month as a billing period. The regulations provide that meters of incrementally priced industrial users shall be read on or before the last day of a calendar month, but may not be read any more than 10 days prior to the end of the month. The limitation of meter readings to the last 10 days of any month carries out our goal of having incremental pricing surcharges reflect as closely as is administratively feasible a supplier's costs for the volumes delivered during the period for which the surcharge is calculated.

This approach will also, we believe, result in the least disruption of current meter practices that would be possible in order to achieve our goal of matching acquisition costs with surcharges. Under the approach, meters of incrementally priced industrial users may be read during a 10-day period of the month. Theoretically, at least one-third of the users on any system are already being read during this period of the month. Given the relatively small number of such users on a system, we believe the rescheduling of meter readings of at most two-thirds of those users should not be a significant burden.

To implement this approach, a provision has been added to § 282.501 which requires that the MSAC of an incrementally priced industrial user for any one calendar month be calculated on the basis of the meter reading made in the last ten days of that month. Meter readings made in the final ten days of any calendar month will be deemed to represent usage for that month. The alternative fuel price ceilings applicable for the calendar month will be utilized to calculate the MSAC's and surcharges applicable to volumes which are covered by the meter readings made in such period.

As set forth in the regulations promulgated in Docket No. RM79-21, the alternative fuel price ceilings applicable for a calendar month will be published no later than the 20th day of the preceding month. Thus, end-users will know the price they potentially will have to bear for their use of natural gas in any month prior to the beginning of that month.

It should be noted that the first meter readings made pursuant to the regulations below, in January, 1980, may reflect a few days of usage during December, 1979, which would not be subject to being incrementally priced. Any such readings should be pro-rated in order to avoid pricing non-exempt users incremental surcharges for their use of gas prior to January 1, 1980.

B. *Time Permitted for Exchange of Information*

As noted above, the primary reason for the 20th of the month billing period proposal was to permit sufficient time for the exchange of information between suppliers and their customers in order to calculate surcharges by the normal billing date for pipeline suppliers. However, many commenters stated that even 20 days—from the 20th of one month to the 10th of the next—would not be adequate for the collection of all necessary information and the calculations needed to compute incremental pricing surcharges. This view was expressed primarily by suppliers that serve a large number of industrial facilities for which surcharges will have to be calculated and who themselves receive gas from several suppliers.

However, those suppliers which have a relatively small number of customers on their systems that will be subject to the first phase of the incremental pricing program and who themselves have a small number of suppliers typically stated that the exchange of information and calculation of surcharges could be accomplished within a 20-day time frame.

Two optional billing procedures are described below which will, we believe, provide adequate time for the exchange of all needed information. In addition, they will allow us to adopt the less disruptive "calendar month" approach described above. Either of the two procedures may be utilized in lieu of billing in accord with the time sequence set forth in the regulations, since the regulations will only provide 10 days for the exchange of information between the end of a month and the typical 10th of the month billing date.

INGAA was a primary spokesman for the position that 20 days would not be adequate for all needed communication and calculations to arrive at the actual surcharges which must be billed under the "reduced PGA" method. INGAA also suggested a solution to this timing problem which appears to be workable. The Commission has determined to adopt INGAA's proposal with respect to sales of natural gas made by interstate pipelines to sale-for-resale customers.

Under this method, an interstate pipeline will have the option of billing a sale-for-resale customer a surcharge for any one calendar month equal to the surcharge estimate which the pipeline used for the customer in order to derive the pipeline's currently effective reduced PGA rate. In the following month, the bill rendered to that sale-for-resale customer will be adjusted by an amount to reflect the difference between the surcharge billed the previous month and what that surcharge should have been, as calculated from actual usage figures and actual alternative fuel price ceilings.

This method will have the effect of allowing a total of up to 40 days for the exchange of information and calculation of surcharges. The Commission believes this time period should be adequate for the passage of required information on even the most complex supply system covered by this Phase I rule.

The regulations below also incorporate the alternative feature which was included in the June 5th proposal with respect to billing by local distribution companies of industrial boiler fuel facilities. Under this alternative, a local distribution company may bill any non-exempt industrial boiler fuel facility it supplies at the level of the alternative fuel price ceiling which is applicable to the facility, and adjust the following month's billing for any resulting overrecovery.

With respect to this alternative, we have altered the final regulations below somewhat from the proposal in that the regulations require any overrecovery to be refunded to the facility from which it was collected. Our proposal indicated that state or local authorities would have jurisdiction as to these refundable amounts. We have been persuaded, however, by several comments submitted on this point that our regulations should require a refund to the party who paid the original amount. Otherwise, the optional billing procedure might result in inequitable treatment of some users. We believe that this requirement does not impinge on state or local jurisdiction, since incremental pricing surcharges are uniquely subject to Federal jurisdiction.

According to all estimates submitted to the Commission since it began considering implementation of Phase I of the incremental pricing program, from the inception and throughout Phase I, gas acquisition costs subject to passthrough by incremental pricing surcharges will exceed the aggregate surcharges which can be passed through to industrial end-users which are not exempt from the program. Thus, industrial users in most cases will be billed surcharges which bring the price of gas up to the level of the alternative fuel price ceilings. In all situations where this will be the case, the two optional billing procedures described above, as compared to billings based on actual data, should not result in any significant difference for affected end-users with respect to the timing of payments.

Furthermore, for those systems as to which all calculations can be made on a current basis, the regulations provide the flexibility for billings to reflect actual data.

V. Calculations Required Under the "Reduced PGA" Approach

The two formulas required to calculate incremental pricing surcharges under the "reduced PGA" approach were set forth in the regulations proposed on June 5th. Each formula was set forth in a projected and actual variant, in §§ 282.503 and 282.504 of the regulations, respectively.

A. MSAC Formula

The formula for the calculation of the maximum surcharge absorption capability (MSAC) of an individual industrial facility was set forth in symbols in §§ 282.503 and 282.504. This formula will be utilized to determine the amount of surcharge which can be passed through to a particular facility before the price of natural gas delivered to the facility rises to the computed price of the alternative fuel which the facility can use.

Several commenters noted that the formula which was proposed on June 5th did not include a variable for state or local taxes which would be applicable to the surcharge. The proposed formula did encompass state or local taxes levied on the price paid for volumes of natural gas were it not for incremental pricing surcharges. However, the formula did not include a variable which would permit appropriate adjustment of the MSAC in those cases where a state or local tax will be levied on the additional amount which will be represented by the surcharge.

The Commission agrees with the comments which noted this point and has adopted the changes to the proposed MSAC formula suggested by these commenters. Therefore, the formulas for a projected MSAC set forth in § 282.503 below and for an actual MSAC, set forth in § 282.504, have been amended from those which were proposed by adding a denominator which will serve to reduce the MSAC by any tax which may be levied on the surcharge. Thus, the surcharge calculated on the basis of this MSAC will be of an amount that will not include the tax which will be added to the surcharge when it is billed to the industrial end-user. These formulas, as revised, will ensure that natural gas costs to non-exempt users will not exceed their alternative fuel costs.

B. Prorating of MSAC

Many commenters disagreed with the formula which was proposed to allocate a total MSAC of a purchaser/supplier among its several suppliers. With respect to volumes of gas which it either purchases directly or produces itself, a pipeline company or distribution company could only take into account under the proposed prorating fraction, in prorating the MSAC on its system to its various suppliers, those volumes of gas which carry incremental gas acquisition costs. However, the formula would permit a pipeline or distributor to take into account in the prorating fraction all volumes of gas which it purchases from an interstate pipeline, irrespective of whether such volumes carry incremental acquisition costs.

Interstate pipelines argued that the supply purchased from sources other than interstate pipelines and that supply which is the pipeline's own production should not be limited to only those volumes which carry incremental costs. Several local distribution companies also argues that their total supply should be utilized in the calculations.

We have given careful consideration to all of the comments submitted on this question. We have, however, determined to adopt the prorating fraction as it was proposed, for the reasons discussed below.

We recognize that our proposed formula involves a different treatment of purchases from other pipelines as compared to direct purchases or production of the pipeline in question. Our determination to adopt this approach is a conscious one based on administrative feasibility.

Several commenters stated that the proposed formula would create a situation where, on a total system, the exempt and non-exempt customers of "downstream" pipelines would end up bearing more than their fair share of incremental gas costs as compared to the customers of "upstream" pipelines. Stated another way, these commenters argued that the proposed formula would result in a shifting of "upstream" pipeline incremental gas costs into "downstream" pipelines' PGA's.

We agree that the prorating set forth in the regulations below could effect such a situation in the case where the incremental costs on a system are less than the MSAC on that system. However, where the converse is true—and, as stated elsewhere in this preamble, the record in this proceeding indicates that the converse situation will be the norm—all non-exempt users on a system will be able to absorb a surcharge in the amount of their MSAC, without absorbing all the incremental costs incurred by the suppliers on the system. Therefore, all such users will be surcharged at the level of the alternative fuel price ceiling from the outset of the program. Under our prorating fraction, no one pipeline or distributor will have to absorb a greater surcharge from each of its suppliers than it is able to pass on to its customers.

However, under the approach urged by the commenters, a pipeline or distributor would effectively shield a portion of the MSAC on its system. This result would occur because the MSAC prorating fraction is designed to result in an amount which, when multiplied by the total MSAC on a system, will represent the amount of the surcharge which a pipeline or local distribution company can absorb from a given supplier. If volumes were included in the denominator of that fraction with respect to which no incremental acquisition costs must be recouped, the larger denominator would result in a smaller MSAC to be reported to the supplier(s).

To the extent a pipeline or distributor could shield a portion of the MSAC on its system, it would be able to price its industrial users, on the average, below the applicable alternative fuel price ceilings.

The ideal approach would be to base the allocation of MSAC's strictly on incremental costs associated with the volumes delivered to any one pipeline or distribution company. This, however, would require a reporting burden of enormous complexity and magnitude. To avoid such a burden, we have opted for an approach which necessitates a certain degree of approximation. Specifically, this approximation involves the reporting "up" a system of supply the MSAC's of each level in the system, and the billing "down" the chain the incremental surcharges based on those MSAC's.

We believe the only alternative to the approach described here would be to adopt the approach to the billing of incremental pricing surcharges proposed in the original January 12th staff proposal—i.e., to compute surcharges on the basis of actual data. We believe that the comments submitted in this proceeding, and especially on the January proposal, have established that a mechanism based on actual data is undesirable and thus not a viable alternative.

The primary differences between the treatment of interstate pipelines and local distribution companies in the prorating fraction is that local distribution companies will not be permitted to include any volumes of its own production of "new" gas therein. No portion of the prices or costs associated with such production are required to be booked into the incremental gas costs account and thus no portion of such costs is subject to passthrough as a surcharge to non-exempt industrial facilities.

One commenter suggested that local distribution company production be treated identically to interstate pipeline production—i.e., that incremental costs be imputed thereto which would then be passed through by way of surcharges. However, the Commission has found no provision in Title II which would lead it to believe or conclude that the Congress intended identical treatment of the production of the two different entities under the regulations implementing Title II.

Specifically, section 203(b)(2) of the NGPA requires that the Commission prescribe rules to determine the "first sale acquisition costs" of natural gas produced by an interstate pipeline. Such "first sale acquisition costs" are then used to determine the portion of the costs subject to being passed through as incremental pricing surcharges. The Congress did not, however, give the Commission similar authority with respect to the production of local distribution companies.

Thus, local distribution companies will include all supplies purchased from interstate pipelines and all supplies purchased from other sources which are within one of the categories described in paragraphs (a) through (k) of § 282.301 in calculating the volume to be used in the denominator of the prorating fraction.

It is appropriate to note here the requirement of section 204(c)(4) of the NGPA. This section states:

> Sec. 204(c)(4) LOCAL DISTRIBUTION COMPANY DIRECT PURCHASES.—In any case in which a local distribution company directly incurs any first sale acquisition cost subject to the passthrough requirements of this title under section 203 or otherwise directly incurs any other cost subject to such requirements under sections 203(a)(8)(B), (9) or (10), such local distribution company shall, with respect to the natural gas involved, be treated for purposes of this title as if it were an interstate pipeline.

Pursuant to this section, any local distribution company that purchases natural gas the price of which is governed by Title I of the NGPA or makes certain other purchases, such as pursuant to the regulations which implement section 311 of the NGPA, is deemed to be an interstate pipeline with respect to those purchases for purposes of the incremental pricing program. Thus, such a company must book into its accounts the portion of the costs of such gas which is subject to passthrough as a surcharge to non-exempt industrial users and must calculate surcharges in accord with the regulations set forth below.

C. Estimated Alternative Fuel Price Ceilings

Several commenters urged that alternative fuel price ceilings be estimated and published at some point this fall for the use of suppliers in projecting MSAC's for individual non-exempt industrial boiler fuel facilities and thus total MSAC's for distribution systems. Pipelines will need these estimates in order to estimate the amount by which their total projected gas acquisition costs can be reduced for purposes of filing reduced PGA rates with this Commission by December 1, 1979.

The Commission is sympathetic to the request that an official estimate of alternative fuel price ceilings would be helpful for the initial estimates required by the regulations below. However, it is anticipated that, as set forth in Docket No. RM79-21, the Energy Information Administration (EIA) of the Department of Energy (DOE) will be the agency which will publish the alternative fuel price ceilings on a monthly basis. We have inquired of the EIA as to whether ceilings could be estimated and published prior to the publication of actual ceilings in mid-December for January, 1980. EIA has stated that it will not be possible to calculate actual ceilings—i.e., ceilings based on collected data—any earlier than mid-December. Further, EIA believes any estimates it might undertake to calculate would be very judgmental.

We believe that pipeline companies and distribution companies will be able to ascertain at least an approximation of fuel oil prices in their service areas which can be utilized for the first series of estimates. Thus, the solution which appears to be most equitable to all parties concerned is to place the discretion in every supplier subject to these rules to utilize estimates of its own choice for the first round of calculations. Furthermore, as explicitly set forth in the regulations, an interstate pipeline is required to provide assistance to any local distribution company it serves in making estimates on alternative fuel price ceilings, if the distribution company so requests.

D. Flat Amount vs. Per Mcf Surcharge

Both the January staff proposal in this docket and the June proposed regulations provided for the calculation of incremental pricing surcharges in flat dollar amounts, rather than on a cents-per-Mcf basis.

The Office of Oil and Gas Policy of the Office of the Assistant Secretary for Policy and Evaluation of the DOE submitted in this docket an analysis of the effect of the two differing methods on various users on a distribution system. That analysis concludes that the two methods do not have different effects once all non-exempt users reach their alternative fuel price ceilings.

During the interval in which some non-exempt industrial end-users are below their alternative fuel price ceilings, the two methods can result in differing effects. End-users which had been paying a lower rate, when compared to other users on the system, prior to establishment of the incremental pricing program would absorb a greater share of the incremental gas costs borne by its supplies under the flat-dollar amount method. These end-users would thus receive a comparatively greater per Mcf rate increase. Those users which had previously paid a higher rate would absorb a smaller portion of the incremental gas costs, or surcharge, borne by its supplier, and thus incur a lower per Mcf rate increase.

As noted by the DOE, however, this difference does not exist once all non-exempt users reach their alternative fuel price ceilings. And, the flat-dollar amount approach results in all users reaching that ceiling at the same time.

This Commission agrees with the DOE's analysis as presented. However, we maintain our original position with respect to this question. Specifically, we believe that a per Mcf approach would be unduly complex from an administrative point of view and that the benefits of that approach do not justify its burdens. The cents-per-Mcf approach would involve much more complex calculations than are required for the approach which has been adopted. Only one other comment in this docket discussed this point, and stated that a cents-per-Mcf approach could cripple the program.

As the DOE analysis indicates, the two methods differ only when incremental gas costs are less than the absorption capability of a particular system. As stated elsewhere in this preamble, all data submitted to date in this docket indicates that non-exempt industrial boiler fuel users will be priced at the alternative fuel price ceilings upon implementation and thoughout Phase I of the program. If experience under the program indicates that the phenomenon analyzed by DOE is in practice a serious problem, we shall review the flat-dollar surcharge approach.

VI. Exemptions

A. In General

Pursuant to sections 206(a), (b) and (c) of the NGPA, natural gas used by small existing (as of November 9, 1978) industrial boiler fuel facilties, agricultural users, schools, hospitals and certain other facilities is exempt from being incrementally priced.

Although these exemptions are granted by the terms of the statute, there still remains the necessity of identifying precisely which facilities qualify under the categories set forth. The Commission proposed in the June 5th Notice to untilize a self-certification procedure for this purpose, similar to the self-certification procedure to be used for the establishment of the alternative fuel capability of an industrial facility, included in the regulations in Docket No. RM79-21.

No comments criticized this approach for the identification of exempt facilities. Thus, the exemption affidavit procedure that was proposed has been adopted in substance in the final regulations set forth below.

The procedure involves essentially two steps. To minimize the burden on industrial end-users, a natural gas supplier is required to first identify from its records which facilities served by it are industrial boiler fuel facilities—that is, industrial facilities which burn natural gas as boiler fuel. The supplier is then to identify from its records, if possible, which of these facilities meet the two-pronged test for an existing small boiler, or, in other words, an exemption pursuant to the terms of section 206(a)(1) of the NGPA. The statute prescribes that a small boiler facility is one which was in existence on the date of enactment of the NGPA—November 9, 1978—and which did not use more than an average of 300 Mcf per day of natural gas as boiler fuel during any month of a base period selected by the Commission. The Commission has determined to use calendar year 1977 as the appropriate base period for purposes of this so-called "interim exemption" for small boilers.

If a supplier can make the above determinations from its records, it need not send an exemption affidavit to a facility thus deterimined to be exempt. The natural gas supplier is required to send an exemption affidavit to all other industrial boiler fuel facilities which it has identified in reviewing its customer list.

B. Exemption Affidavits

The exemption affidavit has been designed by Commission staff and must be used by suppliers in fulfilling their responsibility under the regulations. Copies of the affidavit are available from the Commission's Washington, D.C. Office of Public Information at 825 North Capitol Street, N.E., Room 1000, Washington, D.C. 20426, or upon a telephone request. The telephone number of this office is (202) 357-8055. A copy of the final version of the exemption affidavit is appended to this preamble.

One commenter suggested that a question be added to the affidavit to permit an industrial user to certify that all of its natural gas is used for exempt commercial purposes. We agree with this comment and recognize that a supplier's records might not indicate what otherwise would appear to be an industrial boiler fuel facility is not such a facility.

Therefore, a question has been added to the affidavit which will permit a natural gas user to establish via the affidavit procedure that his facility is not an industrial facility, as defined in the regulations below, which burns natural gas as a boiler fuel.

One commenter suggested that the regulations require that all affidavits be returned to natural gas suppliers. We proposed to require return by only those users who are entitled to an exemption in whole or in part from the incremental pricing program. Users not eligible for a total or partial exemption would not return the affidavits to their suppliers.

The Commission has given careful consideration to this aspect of the exemption procedure and has determined to adopt the approach which was proposed. We believe this approach is consistent with that of other programs which provide for exemptions—that only those desiring the benefit of an exemption should be required to complete some form of an application.

Further, since we are eliminating the annual reaffirmation requirement with respect to exemptions (see discussion below), this approach should not place an undue burden on any natural gas user.

The June 5th proposal contained provisions which would have required natural gas suppliers to make copies of executed exemption affidavits available at their business offices. In addition, suppliers would have been required to make available to the public lists of non-exempt facilities which they are required to compile and file with the Commission.

Many commenters objected to any regulation which would require natural gas suppliers to make available to the public information on the exempt or non-exempt facilities served by that supplier. The Commission has been persuaded by the comments submitted on this topic in both this docket and its companion, RM79-21, that this burden should not be placed on natural gas suppliers. Therefore, we have amended all provisions on public availability of such information.

Natural gas suppliers will be required, however, to send copies of the non-exempt lists required by § 282.204(e)(2) to state or local commissions, in addition to this Commission, in all those instances where such commissions exist having appropriate regulatory jurisdiction. These lists will be available for public inspection at the Commission's Washington, D.C. Office of Public Information. State or local commissions which receive such lists may also make them available for public inspection, if they so choose.

Some commenters also expressed concern about the divulgence of confidential business information if the exemption affidavits are open to public inspection. The Commission does not believe that any of the information which will be included on the exemption affidavits is of a confidential nature. However, if any party completing an affidavit believes differently, he may petition the Commission under the regulations which implement section 502(c) of the NGPA for an adjustment to the regulations governing public inspection of exemption information.

C. Reaffirmation Affidavits

The Commission proposed in the June 5th Notice to require that exemption affidavits be updated, or reaffirmed, on an annual basis, as a means of identifying those facilities which no longer use gas for a statutorily exempt purpose. The Commission believes such facilities should not be entitled to retain their exemptions from the incremental pricing program.

Although it was proposed to require that reaffirmation affidavits be filed on an annual basis, comments were specifically requested on an alternative approach of requiring end-users to inform their suppliers and the Commission of a change in circumstances which would disqualify a facility for an exemption.

The majority of comments addressing this issue stated that the annual reaffirmation procedure would be administratively burdensome. They further stated that requiring the end-user to notify its supplier and the Commission should the use of the facility change from an exempt to a non-exempt status would be sufficient to accomplish the desired goal. One commenter noted that natural gas suppliers are typically familiar with their customers and would know if the owner of a facility was not conducting himself with candor.

The Commission is persuaded that the annual filing of a reaffirmation affidavit is not necessary for successful operation of this program and that it would place an unnecessary burden on industrial users of natural gas. Therefore, the regulations set forth below include a provision, § 282.205, which requires an industrial user of natural gas to inform its natural gas supplier and the Commission if the use of a previously exempt facility changes so that the facility should be incrementally priced with respect to its boiler fuel use of natural gas. Following such notification, of course, the facility will be billed incremental pricing surcharges in appropriate amounts.

Among the comments on this issue was a suggestion that, if a change of circumstances regulation was adopted in lieu of the reaffirmation requirement, the regulations include a sanction for non-compliance. We believe such a provision is unnecessary, but note again the civil and criminal penalities which may be levied under section 504 of the NGPA for noncompliance with regulations which implement the NGPA.

D. Agricultural Use

Section 206(b) of the NGPA requires that the Commission provide an interim exemption from the regulations adopted in Phase I of the incremental pricing program "to the extent of any agricultural use of natural gas" by an industrial facility. This interim exemption is to remain effective until such time as the statutorily required "permanent exemption" for agricultural use becomes effective.

The provision of the June 5th proposed regulations which provided for the agricultural use exemption was § 282.203(b). The definition of "agricultural use" was set forth in the proposed § 282.202(5). This definition was to be utilized in conjunction with the exemption affidavit. The definition proposed was as follows: "Agricultural use" means any use of natural gas which is certified by the Secretary of Agriculture under 7 CFR § 2900.3 as an 'essential agricultural use' pursuant to section 401(c) of the NGPA."

Several commenters argued that this definition should be broadened to be consistent with the definition of "agricultural use" contained in section 206(b)(3) of the NGPA. The commenters pointed out that the 206(b)(3) definition is different from the definition of "essential agricultural use" set forth in section 401(f)(1) of the NGPA, in that the latter definition, while encompassing the same end uses of natural gas, requires the Secretary of Agriculture to further define the agricultural uses of natural gas which are "necessary for full food and fiber production."

The commenters argue that the Secretary of Agriculture's rule, which determines essential agriculture uses, was intended to be used for curtailment priorities only, and not for purposes of determining "any agricultural use" under section 206(b) of the NGPA. One commenter noted that the Secretary of Agriculture, in the preamble to the final rule which certifies essential agricultural uses, expressly recognized that the rule "should not be construed as any indication of what is or is not an 'agricultural use' for purposes of other sections of the NGPA, notably section 206." (44 FR 28784, May 17, 1979.)

Furthermore, one comment pointed out that the language used in the statute, in the Statement of Managers, and in the floor debates consistently maintains a distinction between "any agricultural use" for purposes of incremental pricing and an "essential agricultural use" for purposes of curtailment priorities in section 401 of the NGPA.[3]

The American Textile Manufacturer's Institute (ATMI) argued that the use of natural gas as a boiler fuel in textile manufacturing operations should be considered an "agricultural use", since the manufacture of textiles (insofar as natural fibers are involved) is "natural fiber production and processing".

ATMI noted that, in the Department of Agriculture's final rule, the Secretary of Agriculture determined that the textile industry was not included as an essential agricultural use because, although it would be "eligible for consideration on the basis of being a use for natural fiber processing," such use is not "necessary for full food and fiber production." (44 FR 28784, May 17, 1979)

As ATMI pointed out, the initial stage of textile manufacturing involves the processing of fibers (including natural fibers) for the production of fabric by spinning and weaving or knitting. In the next stage, most textile fabrics move through finishing mills for purposes of adding characteristics such as color, napping, non-flammability, crease resistance, and water repellency. After this process fabrics are in a form such that they may be used in manufacturing other products.

We have carefully considered these comments and have determined that the definition of "agricultural use" proposed in § 282.202(5) should be revised. Thus, the definition of "agricultural use" (§ 282.202(a) in the final regulations) has been revised to include, in addition to the "essential agricultural uses" set forth in 7 CFR 2900.3, the use of natural gas in textile operations to the extent it is used for the processing and finishing of natural fiber into a usable form. The revised regulations reflect the Commission's belief that the manufacture of end products should not be included as a stage of "natural fiber processing".

The regulations below and the exemption affidavit set forth the SIC codes applicable to the textile manufacturing operations which we have determined should be eligible for an interim agricultural use exemption from the incremental pricing program.

E. Interim Exemptions

As noted above, the exemptions herein described for small existing boilers and for agricultural users are, by the terms of the statute, "interim exemptions." Section 206 of the NGPA requires that no later than May 9, 1980, permanent exemptions with regard to these two categories of boiler fuel users be adopted by the Commission.

The permanent exemption for small boilers must be designed so that the entire class of boilers thereby exempted are those which were in existence on November 9, 1978, and whose total usage of natural gas as boiler fuel in 1977 represented only 5 percent of the total volume of natural gas transported by interstate pipelines and used in 1977 as boiler fuel.

The permanent exemption for agricultural use is not to be available to those agricultural users that the Commission determines have an alternative fuel or feedstock which is economically practicable or reasonably available.

It is self-evident that the regulations regarding permanent exemptions for small boilers and agricultural users may well alter the eligibility of users which may be able to obtain exemptions under the "interim rules". Thus, any user who obtains an exemption under the terms of the interim rules should not assume that the exemption will necessarily continue beyond May of 1980.

The Commission intends to begin its effort to implement the statutory provisions regarding the permanent exemptions in ample time to meet the May 9, 1980 statutory deadline.

F. Other Exemptions

In the June Notice, the Commission announced that it intended to issue within a few weeks a Notice of Proposed Rulemaking to deal with boilers of the size granted a statutory exemption from the incremental pricing program—300 Mcf usage per day or less—which have been constructed since the date of enactment of the NGPA. (By its terms, the statute grants an exemption only to those "small" boiler facilities which were in existence on the date of enactment.)

It also was announced in the June Notice that three dockets had been established to receive comments on the question of whether a rulemaking proceeding should be instituted to address three other classes of exemptions: (1) for so-called "load-balancing" facilities which burn oil as their alternative fuel; (2) for "load-balancing" facilities that burn coal as their alternative fuel; and (3) for entire states whose ratemaking practices accomplish the same goals as the incremental pricing program hereby established.

Many commenters urged that all of these exemption questions be answered as soon as possible, so that pipelines and distributors can determine exactly which customers will be subject to the regulations below, and so that pipelines can accurately predict the amount of surcharges their non-exempt customers will absorb and thus calculate the amount by which their PGA rates should be reduced.

We are sympathetic to the requests of pipelines that they be able to enter into the calculations required for the new "reduced PGA" approach with some degree of certainty. We will proceed as rapidly as possible on all outstanding questions, but believe that some estimating will be required by both pipelines and distribution companies.

As announced, we are issuing the Notice of Proposed Rulemaking in Docket No. RM79-48 with respect to new small boiler facilities. We will, as stated in that notice, hold a public hearing on the proposal as part of the public comment procedure and anticipate promulgating a final rule early in November. That final rule will, as is set forth in the Notice of Proposed Rulemaking, be subject to Congressional review.

We also are issuing notices in Docket Nos. RM79-45 and RM79-46 stating that rulemaking proceedings will not be instituted in either of those dockets. The rationale for our determinations in each are set forth in the respective notices.

Finally, by notices of August 22, 1979 (44 FR 50063, August 27, 1979) and September 10, 1979 (44 FR 53178, September 13, 1979), we extended the comment period in Docket No. RM79-47. As we have stated previously, we

[3] *See, e.g.*, H.R. Rep. No. 95-1752, 95th Cong., 2d Sess. 102-103, 112-113 (1978); 124 *Cong. Rec.* S14,957 (daily ed. Sept. 12, 1978) (remarks of Sen. Talmadge).

believe states cannot make informed comments on the question of state-wide exemptions until they know the details of the regulations adopted in this docket (RM79-14) and its companion, Docket No. RM79-21, both of which are issued today. A separate notice will be issued in the near future stating the date until which comments will be accepted in Docket No. RM79-47. We intend to move expeditiously on Docket No. RM79-47 once the period for receipt of comments has closed.

Many commenters urged that if all exemption questions could not be answered concurrently with adoption of regulations in Docket Nos. RM79-14 and RM79-21, provisions be included in the regulations in this docket (RM79-14) to permit interim exemptions. It was argued that such exemptions should be allowed until finalization of the Commission's position on outstanding exemption questions, provided the owner of the facility desiring the exemption filed a bond or undertaking in an amount established by the Commission to cover its liability should the facility ultimately be determined not to be eligible for an exemption.

We have given serious consideration to the concept of an interim exemption, but have determined not to incorporate such a procedure in the regulations hereby adopted. We believe an interim exemption procedure would create the potential for abuse and that high priority and exempt industrial users, as well as other non-exempt industrial users, might never be made whole if it were ultimately found that an interim exemption had been unjustifiably obtained.

As we have stated previously, any party may file for an adjustment of any of the regulations below under the procedures set forth in § 1.41 of the Commission's regulations in Title 18, Code of Federal Regulations. These regulations implement section 502(c) of the NGPA, as it relates to exceptions to certain NGPA regulations.

The Commission has the capability of processing § 1.41 petitions rapidly and believes that it will be able to handle any such petitions which arise due to the regulations below in an expeditious and equitable manner.

VII. Submetering

A. Proposed Treatment

The June 5th Notice described the background of the Commission proposal incorporated therein to require that volumes of natural gas used for exempt purposes within an industrial boiler fuel facility be measured by submeters in order not to be incrementally priced. Under the proposed procedure, exempt volumes could be determined by submetering either exempt or nonexempt volumes, if the volume of exempt usage would thus be based on verifiable meter readings.

The submetering proposal was based on the following conclusions: that considerable in-plant submetering already is being done; that submeters can be purchased and installed at reasonable cost; and that the alternative of using estimates on a long-term basis, with verification of same performed by data verification committees, was not viable.

The June Notice also set forth the Commission's belief that end-users should own and bear the cost of submeters, since the end-users will benefit from submeters in that submeters will permit them to obtain an exemption from incremental pricing for a portion of their natural gas consumption. Further, the Commission concluded that ownership by end-users would maximize the tax benefits which would accrue from new installations of submeters.

As one aspect of its proposal, the Commission indicated that it might be necessary to rely on estimates in the short-term, in order to allow time for the installation of all submeters which would be required.

B. Comments Received

Considerable comment on submetering was received both at the June 27, 1979, hearing in this docket and in the written comments submitted in response to the Notice of Proposed Rulemaking.

Numerous commenters set forth the argument that submetering should not be mandated until the regulations implementing Phase II of the incremental pricing program are finalized, since those rules may obviate the need for many submeters which would be installed for Phase I purposes.

Further, several parties expressed serious concern whether the number of meters required could be obtained and installed by the proposed incremental pricing implementation date of January 1, 1980.

Several commenters argued that natural gas used for a non-boiler fuel purpose is exempt from incremental pricing by the terms of the statute itself. Therefore, these commenters argue, end-users should not have to bear any cost in order to receive the exemption from higher prices.

The cost and adminstrative burden which would be imposed on the natural gas industry and industrial consumers by a submetering requirement was discussed extensively. Several commenters provided statistical data and cost estimates for submetering in specific instances which indicate that on average, the unit cost per meter, including site preparation, related piping, etc., may be about $10,000, or twice the estimate set forth in the June Notice.

Further, it was generally claimed that the extent of in-place submetering is not nearly as widespread as envisioned in the Notice. Some commenters alleged that requiring installation of submeters will impair efforts to market natural gas and may induce some boiler fuel users to forego using natural gas (where such use is a small fraction of total use).

Some commenters argued that requiring submeters (paid for by the users) would raise the cost of gas above alternate fuel costs. Commenters also stated that in some instances it is physically and/or economically impractical to install submeters, due to the configuration of the particular industrial facilities in question. Where by-product gases from other processes are mixed with natural gas in order to fuel a boiler, it was argued that it would be most difficult, if not impossible, to install a submeter which could measure the volume of natural gas thus being used.

Also, commenters argued that in the instances where the boiler output (steam and/or electricity) is used for both exempt (such as agricultural) and non-exempt purposes, submetering would be useless because other techniques must be employed to determine the exact exempt and non-exempt volumes.

Further comment was offered to the effect that even if submeters already exist, or are subsequently installed, it does not follow axiomatically that such meters are suitable for billing purposes. The customer and the supplier might have differing requirements on such factors as pressure, temperature and Btu corrections. Other problems which were noted included the problems attendant to regular verification of the meter, which party would be responsible for reading and upkeep of the meter, etc. A number of commenters opposed our tentative decision that end-users should bear the cost of submetering.

Many of the commenters who opposed a mandatory submetering requirement proposed in the alternative that exempt or non-exempt volumes be determined and attested to by qualified engineers on a monthly basis, or that such volumes be determined by agreement between the supplier and the purchaser. Those commenters which urged the use of estimates argued for certified submissions rather than the formerly advocated use of data verification committees. Some commenters suggested that curtailment case data be used to determine the volumes of exempt and non-exempt purchases.

A few commenters believed that the proposal raised a "Catch 22" problem with respect to small boilers. These commenters interpreted the regulations to require installation of a submeter in order to obtain an "under 300 Mcf per day" exemption. Commenters noted that once the low usage was established, however, the submeter would no longer be needed, since the facility would be exempt from the program.

C. Treatment Adopted

Based on our current knowledge regarding submetering, the Commission believes the approach of requiring installation of submeters is the only one available to insure implementation of the program in the manner which was envisioned by the Congress.

We are persuaded, however, that it is appropriate to extend the submetering requirement until such time as the scope of the Phase II regulations of the incremental pricing program is established. We cannot now speculate on whether the yet-to-be written section 202 rule will reduce the need for submetering. That rule may even expand the need for submeters.

The Phase II regulations, required by section 202 of the NGPA, must be submitted to the Congress for its review. By the statute, the Congress must be allowed 30 days for review, which is to be 30 days of continuous session as defined in the statute. In order to allow ample time for 30 days of continuous session following May 9, 1980, and to allow for a period of time for the purpose described below following that date, we have determined to require installation of submeters by November 1, 1980, unless the Phase II regulations make alteration of that requirement appropriate.

If Congress should disapprove the Phase II regulations which the Commission must promulgate, boiler fuel users would have a period of at least 30 days, based on our calculations, in which to install needed submeters. As set forth in the regulations below, a purchase order for the required submeters would satisfy the November 1, 1980 installation requirement.

Therefore, the regulations below permit the use of estimates and/or supplier-customer agreements until November 1, 1980. Absent the installation of operational submeters by November 1, 1980, or the acquisition of a purchase order for submeters by that date, all volumes sold to a non-exempt industrial boiler fuel facility on or after November 1, 1980, will be deemed subject to incremental pricing.

We accept that the estimate on the cost of a submeter which was included in the June 5th Notice may not have been illustrative of most situations and therefore may have been lower than what the cost generally will be. However, even accepting an estimate twice that of ours, and not taking into account the offsetting tax benefits, the payback term for such installations would be only about 100 days for a customer which thereby received a 10 cents per Mcf reduction in the cost of gas for exempt uses of approximately 1000 Mcf per day.

The generally short payback times which reasonably may be expected, and the advantage of having exempt and non-exempt volumes determined on a uniform basis to the greatest extent possible, in our opinion justify the requirement for installation of submeters.

We believe that the capital cost of submeter installations should be borne by the consumer, since submetering will serve to quantify the exempt volumes entitled to lower rates. We have not addressed the question of who should actually own the submeter, and thus leave this question to the consumer and supplier, or the regulatory body which has jurisdiction. We further believe that submeter installations should be subject to the natural gas supplier's accuracy and safety standards, security control and access as needed for reading and maintenance. To do otherwise would create the potential for undue discrimination against other consumers. However, none of the Commission's views on these questions have been included as mandatory requirements in the regulations. These questions are thus left to suppliers and customers to resolve as is appropriate and workable.

This Commission has determined that the long-term use of estimates would not be a viable regulatory approach for establishing volumes of gas used for non-exempt purposes. The primary weakness in the use of estimates is that a strong motivation would exist to estimate low for non-exempt consumption (and therefore high for exempt consumption). It is equally apparent that a multiplicity of estimating techniques would be employed, reflecting both the preferences of numerous individual estimators and a wide variety of individual fact situations.

Similarly, suppliers and their customers could be strongly motivated to agree to low non-exempt volume figures, since by so doing costs that otherwise would be borne by non-exempt sales would be shifted to others, including customers of other distributors and other pipelines, and in other states.

Further, we foresee a large verification burden if either the engineering estimate or the seller-buyer agreement approach were adopted on a long-term basis. By requiring the installation of submeters, we believe questions of motivation will be largely avoided and verification burdens will be minimized.

The use of curtailment case data to determine exempt/non-exempt breakdowns would not be appropriate. In most instances, such data reflect past base period conditions and in our opinion should not be used as a basis for current billings.

As stated above, estimates or supplier/customer agreements will be utilized for the period January 1, 1980 through October 31, 1980. The regulations below provide that as of November 1, 1980, all volumes claimed to be used for exempt purposes must be based on appropriate submeter readings. We believe that even in those situations where a mixed stream is fed into a boiler, or where the output of a boiler is used for both non-exempt and exempt purposes, the installation of submeters would aid in arriving at a more accurate estimation of the non-exempt usage. We therefore encourage installation of submeters at strategic points which would allow for closer estimates than otherwise could be obtained. This aspect of the submetering problem will be discussed, however, in detail at the technical conference to be held in early November, as described below.

Those commenters which suggested a "Catch 22" problem with respect to small boilers perceived a problem which does not exist. The proposed regulations, and final regulations below, provide for the "under 300 Mcf" exemption on the basis of attestations for 1977.

D. Technical Conference

The above described approach for quantifying volumes which are consumed for boiler fuel in conjunction with volumes which qualify for exemption from the incremental pricing program represents the determination this Commission has reached following consideration of the entire record developed in this docket.

However, we are seriously concerned by several of the arguments which have been voiced in opposition to a mandatory submetering requirement. In particular, we are concerned about imposing a disproportionately large cost on industrial end-users which would serve no purpose other than to meet the requirements of this program. We are also seriously concerned about those situations as to which it has been alleged submeters could not provide an indication of the volume of natural gas actually consumed as non-exempt boiler fuel.

The regulations set forth below will permit the use of estimates or supplier/customer agreements in order to calculate non-exempt usage for the period January 1, 1980 up until the required installation date of November 1, 1980. We believe it would be useful for all concerned parties and for this Commission to develop standardized methods by which such estimates will be made. It is our intention to issue guidelines on such standardized procedures prior to the date on which the first set of estimates will have to be made under the regulations below.

In order to aid us in the development of these guidelines, we will hold a technical conference on the topic of submeters. Further, if the information submitted at this conference should indicate that revisions should be made to our submetering requirement, we will propose to amend the regulations hereby adopted in an appropriate manner.

The technical conference will be held in Chicago, Illinois in early November. The exact date, time and location of the conference will be announced in the near future. The Commission technical staff will chair a panel, and it is hoped that a round-table discussion format can be used.

It is our hope that technical personnel representing industrial end-users will attend the conference and offer as much detailed information as possible to Commission staff on the many aspects of submetering which have been raised thus far in this proceeding. Additionally, we request detailed recommendations concerning the use of estimates for quantifying exempt and non-exempt volumes, in particular as to how such estimates could be standardized and verified. We also intend to invite representatives of meter manufacturing firms to attend this conference.

Natural gas suppliers which are included in the incremental pricing program are hereby requested to assist the Commission in the compilation of a list of industrial users and manufacturers of meters who should be invited to this technical conference. The Commission will send invitations to as many industrial end-users of natural gas and meter manufacturing firms as it is able to identify, and thus requests assistance in the identification effort.

The invitations which will be sent will specifically request that those representatives of end-users who attend the conference be persons who are familiar with day-to-day plant operations and who can offer comments based on actual experience as to the advantages and disadvantages, and attendant difficulties of installing submeters in industrial facilities.

Finally, the Commission hereby wishes to make clear its intention, should this technical conference result in the acquisition of no further information than it has at present on the subject of submeters, and should the Phase II regulations not obviate the need for submeters, to proceed with allowing the submetering requirement incorporated in the regulations below to become fully effective on November 1, 1980.

VIII. Direct Sales

The proposed regulations set forth in the June 5th Notice provided that the MSAC of an industrial user served directly by an interstate pipeline would be calculated as the difference between the contract price the user was paying and the alternative fuel price ceiling applicable to the facility. The Notice also, however, set forth five alternative formulas for the calculation of the MSAC of a direct sale customer of an interstate pipeline.

The Commission stated that it was soliciting comment on the question and the six alternatives proposed, and that it had not made a preliminary determination as to which approach was appropriate or whether there existed any jurisdictional questions with respect to any of the alternatives.

Many comments were submitted on this question. Pipeline companies that have direct sale non-exempt industrial customers argued that the Commission's regulations cannot utilize anything other than the contract rate for the calculation of surcharges as to such users. These commenters argued that incorporation of any of the five alternative formulas into the regulations would result in *de facto* rate setting, a function outside the ambit of Commission authority.

Commenters who opposed the choice of contract prices for MSAC calculations argued that the question is not one of rate-setting. These commenters argue that the Commission is required to prescribe a method whereby incremental gas costs will be passed through to industrial users who are served directly by interstate pipelines. These commenters assert that if the Commission were to adopt the "contract price" approach, incremental gas costs would *not* be passed through to direct sale customers. Rather, these commenters allege that interstate pipelines would simply increase their contract prices to the applicable alternative fuel price ceilings, and any increase that would otherwise have represented an incremental pricing surcharge would then represent profit to the pipeline.

In such a scenario, incremental gas costs would first be passed through to industrial customers of sale-for-resale customers of the pipeline, and then to all customers when the non-exempt industrial customers could no longer absorb surcharges. This would result in exempt customers ultimately bearing costs which Congress intended should be borne by industrial users.

The Commission has given very serious consideration to this question. The Commission's deliberation has resulted in a determination that it has the authority to insure the passthrough of incremental gas costs to direct customers of interstate pipelines.

The Commission gives great weight to two provisions of Title II and believes such provisions make clear that Congress intended the Commission have authority to take such action as is necessary in order to insure that the full intent of Title II is carried out.

Section 204(c)(2)(B), as well as other provisions, states that surcharges are to be passed through to direct as well as indirect industrial customers:

(2) SURCHARGE PASSTHROUGH.—The rule required under section 201 (including any amendment under section 202) shall provide

* * * * *

(B) one or more methods for imposing such surcharge on the rates and charges of such pipeline applicable to any volume of natural gas delivered, during the calendar period involved, for industrial use to any incrementally priced industrial facilities served directly by such interstate pipeline and to incrementally priced industrial facilities served indirectly through any other interstate pipeline or any local distribution company.

In addition, Section 204(c)(2)(D) states as follows:

(D) EXCEPTION.—The methods prescribed under subparagraphs (B) and (C) need not require—

(i) elimination or reduction under subparagraph (B) of the surcharge with respect to any specific deliveries of natural gas; or

(ii) the increase under subparagraph (C) of the surcharge generally applicable due to any adjustment under subparagraph (B); if the Commission determines that to do so would be impracticable or unnecessary to carry out the purposes of this title.

The Commission interprets section 204(c)(2)(D) to place in it the authority to take whatever action may be necessary, including not to permit a reduction in the surcharge to a particular industrial facility, in order to "carry out the purposes" of Title II.

The Commission thus believes that the statute does not state that the surcharge must always be reduced in order to bring the price of gas down to the alternative fuel price ceiling with respect to a particular user. The Commission takes this view because it believes that in a situation where the Commission determines that a surcharge of a certain magnitude should continue to be passed through to an industrial user, it would be within the power of the customer not to agree to a higher contract price.

The Commission agrees in theory with the comments which argued that Title II simply requires an alteration of the Commission's traditional cost-allocation methods between jurisdictional and non-jurisdictional customers. Pursuant to Title II, gas cost acquisition costs can no longer be allocated on a strictly volumetric basis. Title II significantly amends the manner in which gas acquisition costs are to be allocated, and requires that certain portions of those costs be allocated to industrial customers not exempted from the program, regardless of whether those customers are served by the pipeline indirectly through local distribution companies, or served directly by the pipeline itself.

The Commission's deliberation on the direct sales question has resulted in a determination to adopt the regulations which were proposed with respect to this area. Thus, the Commission envisions that the MSAC of a non-exempt industrial customer served by an interstate pipeline will be calculated as the difference between the contract price which has been negotiated by the customer and the pipeline and the alternative fuel price ceiling (with appropriate adjustments for taxes) applicable to the customer's facility.

The Commission has chosen this approach for several reasons. First, we have insufficient data on the direct sales market—due to the fact that this Commission did not have rate-setting jurisdiction with respect thereto under the Natural Gas Act—to allow us to conclude whether the potential for circumvention of the intent of Title II is real or merely theoretical. If real, we also lack data on the extent of the potential and thus whether the problem warrants adoption of a regulatory solution.

If a solution is warranted, the record in this proceeding clearly indicates that further information and discussion is needed before a regulation could be promulgated which would be both administerable and equitable.

However, we intend to monitor the activity in the direct sales market over the next several months, and if it is found that contracts are being negotiated in an abnormal manner in order to eliminate potential surcharge absorption capability, the Commission may take action to prevent such a circumvention of the intent of Title II.

The Commission is also looking into whether a potential such as that described with regard to direct sale customers of interstate pipelines exists with respect to industrial customers of some local distribution companies. If such a situation should be found, the Commission will consider taking appropriate action with regard thereto.

IX. Scope of the Regulations

A. Definitions

Some commenters suggested that the definition of "industrial facility" which was proposed in the June 5th Notice was not broad enough to include all operations which are commonly considered to be industrial in nature. The definition proposed would have included only "any facility which primarily changes raw or unfinished materials into another form or product." It was noted that this definition would not include facilities engaging in extraction or processing activities which do not necessarily result in another "form" or a different "product."

We agree that our proposed definition was not sufficiently broad. Therefore, we have adopted the following definition of "industrial facility" for inclusion in § 282.103 of the regulations below:

"Industrial facility" means any facility engaged primarily in the extraction or processing of raw materials, or in the processing or changing of raw or unfinished materials into another form or product.

Several commenters also raised queries about the exact definition of a "facility". The NGPA does not set forth a definition of the term, nor did the proposed regulations endeavor to define the term. We believe, however, that it would be useful to include a definition of this concept so as to correct any confusion or misunderstanding that a single boiler could qualify as a facility. We believe a definition of "facility" will be especially helpful for the application of the rule proposed in Docket No. RM79-48 with respect to small boilers constructed since the date of enactment of the NGPA.

Therefore, we have included in § 282.103 of the regulations below a definition of facility as follows:

"Facility" means all buildings and equipment located at the same geographic site which are commonly considered to be part of one plant, mill, refinery, or other industrial complex.

B. Exempt End-Uses

Several commenters discussed the point that Title II is drafted in a somewhat confusing manner with respect to its coverage and the exemptions granted thereto. Specifically, the provisions of Title II are only to apply to "boiler fuel use of natural gas by any industrial boiler fuel facility." The statute goes on, however, to set forth specific exemptions from the requirements of the statute for "any school, hospital, or other similar institution"—facilities which are not commonly thought of as industrial and thus would be outside the scope of the statutory provisions without the specific grant of an exemption.

Because the somewhat inconsistent treatment in the statute leads to a certain amount of confusion, several commenters urged us to set forth specifically that the regulations for the incremental pricing program are not applicable to the use of natural gas in facilities which are not industrial facilities.

We agree that the statutory structure can lead to confusion and that it would be helpful to clarify that the regulations below do not apply to the use of natural gas for uses other than boiler fuel use by industrial facilities. Thus, we have revised § 282.203 of the regulations below to include a provision stating that the incremental pricing regulations apply only to industrial facilities which use natural gas as a boiler fuel.

C. Ignition Fuel and Flame Stabilization

Several commenters raised the question of whether gas consumed in boilers for ignition fuel and flame stabilization (IF&FS) purposes should be treated as boiler fuel under incremental pricing. The comments noted the pendency of IF&FS issues in other proceedings (e.g., El Paso Natural Gas Co., Docket No. RP76-2 (Ignition Fuel and Flame Stabilization)). The basic issues in those proceedings, however, differ from the issue here. Those proceedings are concerned mainly with whether such usage should be accorded high priority (process use) status, and with alternate fuel capability and conversion costs for curtailment purposes.

In those proceedings, it is argued that IF gas is used for one of three purposes: to achieve initial combustion of another fuel in pilot ignitions; to warm up the boiler to enable safe and complete ignition of a less volatile primary fuel (usually oil or coal); and to maintain temperature in non-base load units.[4] The first two uses are intermittent; the third is longer term, but it is not needed after firing by another fuel commences.

FS gas, by contrast, is used to avoid flameouts resulting from momentary breaks in the supply of another fuel, which can pose operational and safety problems. The use of gas for flame stabilization is a continuous use during boiler operation.[5]

The record in Docket No. RP72-6 (IF&FS) reveals generally that IF gas consumption is small by comparison to FS consumption. The latter, however, often is a significant fraction—25 percent or more—of total gas consumption.[6] The same record reveals that IF&FS gas was used by approximately 130 customers served directly and indirectly by El Paso Natural Gas Company. The preponderance of volume, however, was used in electric utility boilers.

We believe that regardless of our eventual resolution of the curtailment case issues, IF&FS gas should not be summarily exempted from incremental pricing when burned in industrial boiler fuel facilities in quantities, by persons, and for purposes which are not statutorily exempt. To treat IF&FS gas otherwise would lead us to similarly exempt warmup, temperature maintenance and pilot fuel in straight, natural gas fired boilers as well. Such a result would, we believe, be contrary to the letter and spirit of the statute. Furthermore, since FS gas contributes meaningfully to the total energy input to operating boilers, it should be regarded as boiler fuel.

Our conclusion with respect to these two uses of natural gas is, of course, a generalized one. Any user who believes that his situation merits special consideration may file a request for an adjustment to these regulations pursuant to § 1.41 of the Commission's regulations.

X. Refunds

One commenter noted that the proposed regulations did not address the question of how jurisdictional refunds attributable to periods prior to January 1, 1980, but which had not been paid as of that date, should be treated. The comment further noted that it appeared that non-exempt customers would not receive any benefit from such refunds under the "reduced PGA" approach.

This result would occur because non-exempt customers, according to the majority of data provided to us, will be priced at the applicable alternative fuel price ceiling for their use of natural gas from the inception and throughout Phase I of the program. If refund payments were simply used to reduce the 191 account (as has been done in the past) the PGA rate applicable to all customers would be reduced. Non-exempt customers, however, would then simply bear a larger surcharge and effectively not receive the benefit of the refund.

The Commission has determined that such a result would be inequitable to non-exempt customers and that, in contrast, non-exempt customers should receive the full amount of refunds to which they are entitled with respect to gas service purchased prior to implementation of the incremental pricing program.

Therefore, the Commission has included a provision in the regulations below to deal with the jurisdictional portion of refunds applicable to the period prior to January 1, 1980, which are ultimately determined to be payable for sales to non-exempt industrial users. One possible regulatory solution would have been to revise the formulas to be used for the calculation of MSAC's. This approach, however, would have resulted in further complexity in a formula which is already highly technical. Moreover, we believe the problem of refunds will be of limited duration and it would thus be inappropriate to solve the problem by amending regulations which will have a longer applicability.

Therefore, it appears that a separate regulatory provision to address this problem is most appropriate. Accordingly, a new § 282.506 is included in the regulations herby adopted. This regulation requires that the jurisdictional portion of refunds applicable to non-exempt industrial facilities determined after December 31, 1979, to be applicable to periods prior to January 1, 1980, plus the interest applicable thereto, shall be paid in a lump-sum payment to the suppliers of the non-exempt facilities on the dates prescribed by the Commission orders which require the refunds.

The lump-sum payments are to be made to the sale for resale customers for the benefit of their non-exempt customers to whom the sales for which refunds are ordered were made. The amounts of the refunds thus payable will be calculated on the basis of the sales made to the non-exempt customers during the period when the supplier rates which give rise to the refund were in effect.

The treatment of the jurisdictional portion of all refunds applicable to periods after January 1, 1980, will be governed by section 154.38(d)(4)(vii) of the Commission's regulations.

XI. Filing Requirements

The proposed regulations contained a provision to require the filing of informational tariff sheets which would reflect the incremental pricing surcharges projected for non-exempt customers and used in calculating "reduced PGA" rates. The final regulations below incorporate this filing as a mandatory requirement (not limited to informational purposes) in § 282.602(a)(1)(ii). These filings will permit commission staff to audit billings which are calculated in accord with the optional billing procedure for pipelines described in section IV. B. above.

Several commenters objected to the provision set forth in proposed § 282.602(d)(2) which would require the filing of information as to each source of supply by API well identification number. The Commission recognizes that such a requirement will result in the filing of significantly more detailed information than is filed at present. However, the Commission believes that only this information will enable staff to audit the incremental gas costs which are used in calculating "reduced PGA's". Staff anticipates performing spot audits of the revised tariff sheets.

Pipelines are hereby informed that no specific format is prescribed for the submission of this well-by-well information, and that submission of a copy of a company's computer print-out with this information will satisfy this requirement.

Further, one change has been made to the regulations as proposed in that the well-by-well information is only required to be submitted if it is available. The Commission believes that this information is in fact in most instances kept as a matter of course.

XII. Environmental Issues

A few commenters continue to urge that a complete Environmental Impact Statement should be prepared with respect to these regulations. As stated in our June 5th Notice, an Environmental Assessment of these regulations was prepared and the conclusion was reached therein that the proposed regulations would not be a major Federal action significantly affecting the quality of the human environment.

None of the comments submitted in response to the June 5th Notice have led us to conclude that our original position on this issue warrants further consideration or a change in our original

[4] See: Administrative Law Judge's September 15, 1978, Initial Decision, mimeo pp. 15–16.

[5] *Supra.*

[6] Exhibit No. 27; the consumption of other fuels is not shown.

conclusion. Thus, an Environmental Impact Statement with respect to these regulations will not be prepared.

XIII. Special Circumstances

We have noted several times in this preamble and in its companion document in Docket No. RM79-21 that § 1.41 of the Commission's regulations provides procedures whereby individual parties may request an adjustment to the regulations below if it is believed these regulations will result in special hardship, inequity, or an unfair distribution of burdens.

We also note the recent adoption by the Commission of interim regulations which provide procedures whereby individual parties may seek an interpretation of the NGPA or any rule or order issued thereunder. These regulations appear at 18 CFR 1.42, and were issued on August 7, 1979 in Docket No. RM79-65 (44 FR 48171, August 17, 1979). Under these regulations, an interpretation will be issued only if the action which forms the basis for the request is completed or is likely to occur. Interpretations will generally not have precedential value and will be issued by the General Counsel of the Commission.

XIV. Effective Date

In the June 5th Notice we proposed that the incremental pricing regulations included in Docket Nos. RM79-14 and RM79-21 would become effective September 1, 1979. We have determined, however, to make the regulations effective as of November 1, 1979. The regulations still require that incremental gas costs begin to be booked in by natural gas suppliers as of January 1, 1980, and that incremental surcharges commence being billed for usage during the month of January, 1980.

The effective date of the incremental pricing regulations governs the date on which the price of certain categories of high-cost natural gas will be decontrolled, as set forth in section 121(b) of the NGPA. Further, section 201(a) of the NGPA prescribes that regulations to implement Title II must be made effective no later than 12 months following enactment of the NGPA, i.e., November 9, 1979. We believe it is consistent with the scheme envisioned in the statute for establishment of the incremental pricing program and the decontrol of certain types of high-cost natural gas to make the regulations below effective as of the first day of the month in which the mandatory effective date falls.

The sections of the regulations below governing the obtaining of exemptions, sections 282.201 through 282.206, are being treated in a manner different than the majority of the regulations and are being made effective October 15, 1979. It is necessary that exemption affidavits be mailed out by natural gas suppliers to their customers by that date in order that the "reduced PGA" rate can be calculated by December 1, 1979. As required by section 553(d) of Title V of the United States Code, the Commission thus finds that good cause exists to make these six sections of the regulations below effective October 15, 1979, less than 30 days subsequent to publication of the regulations.

XV. Time Line

In our June 5th Notice, we included a summary time line of the events which would take place under the regulations in this docket and its companion, Docket No. RM79-21. A number of comments were submitted on various aspects of the time line and the suggestion made that more details should be included therein. Obviously, also, the new effective date for the regulations requires a significant revision of the time line which was proposed.

Set forth below are two separate time lines which we believe will be of aid to all parties in implementing these regulations in the most timely manner possible.

The first time-line is similar to that included in the June 5th Notice; it sets forth the major steps which must take place under the regulations. The second time-line describes the steps which must take place on a monthly basis in order to arrive at monthly surcharges pursuant to § 282.504 of the regulations.

A. Time Line for Implementation of Program

October 3, 1979—Exemption affidavits and alternative fuel price ceiling affidavits available through the Office of Public Information.

October 15, 1979—Sections 282.201–282.206 of the regulations become effective. Natural gas suppliers mail exemption affidavits to all industrial boiler fuel facilities which were not determined to be exempt from an examination of the natural gas supplier's own records.

November 1, 1979—Major portion of regulations become effective. In accordance with the natural gas suppliers' requests as contained in the suppliers' mailings of October 15, exemption affidavits are returned to natural gas suppliers by industrial boiler fuel facilities claiming an exemption in whole or in part.

November 1, 1979—Interstate pipelines file revised PGA provisions and incremental pricing surcharge provisions; pipelines and local distribution companies determine projected MSAC's.

November 15, 1979—Local distribution companies notify supplying pipelines of their projected MSAC's for the period commencing January 1, 1980.

November 30, 1979—Interstate pipelines file reduced PGA tariff sheets and estimated incremental pricing surcharge tariff sheets for the period commencing January 1, 1980.

December 20, 1979—Incremental pricing ceilings for January, 1980 are published.

January 1, 1980—Effective date of tariff sheet filed November 30, 1979. Incremental gas acquisition costs begin to be booked by natural gas suppliers.

January 15, 1980—Natural gas suppliers file lists of non-exempt industrial boiler fuel facilities with the Federal Energy Regulatory Commission and with state or local commissions having jurisdiction.

January 2, 1981—Natural gas suppliers review customer lists and list of non-exempt industrial boiler fuel facilities filed on January 15, 1980 to determine which facilities should be included on January 15, 1981 list.

January 15, 1981—Natural gas suppliers file updated lists of non-exempt industrial boiler fuel facilities with the Commission and with state or local commissions having jurisdiction.

B. Surcharge Billing Time Line

This time line assumes that needed information will be communicated by distributors to supplying pipelines and between pipelines by telephone, and that such information will later be confirmed in writing. In the outline, Months A, B, C and D are any four consecutive calendar months.

The time sequence set forth in items 1–14 does not reflect the additional time which will be available to pipeline and distribution companies if they choose to follow the two optional billing procedures included in the regulations. Items 15 and 16 *do* reflect the optional billing procedures.

1. Distributors read meters of non-exempts from the 21st day of Month B to the 31st day of Month B.

2. Distributors calculate MSAC for each non-exempt customer based on:

(a) Month B rates,

(b) Month B alternative fuel price ceilings published on the 20th of Month A, and

(c) consumption based on meter readings taken from the 21st to 31st day of Month B.

3. Distributor totals MSAC's of all non-exempt customers.

4. Distributor allocates MSAC between suppliers based on the Month B purchase volumes.

5. Distributor notifies supplier of Month B MSAC on or about the 4th of Month C.

6. Pipelines with direct sales will follow the same reading and MSAC calculation procedures listed in items Nos. 1 to 4.

7. Pipeline totals MSAC on its system for Month B.

8. Pipeline allocates the Month B MSAC between suppliers based on Month B purchase and production volumes.

9. Pipeline notifies its suppliers of their share of the Month B MSAC about the 6th of Month C.

10. Subsequent pipeline to pipeline upstream movement of data should take one day.

11. The most upstream pipeline totals all the MSAC on its system for Month B.

12. The most upstream pipeline compares this total MSAC for Month B to its total incremental costs for Month B.

13. The most upstream pipeline notifies its customers of the amount of surcharge each will be billed for Month B (based on the lesser of MSAC or incremental costs determined in #12).

14. This notification continues from pipeline to pipeline down to the most downstream pipeline. This information must reach the most downstream pipeline on or about the 8th of Month C in time for the regular Month B bill on or about the 10th of Month C.

15. On or about the 10th of Month C:

(a) *Pipelines may either:*

(1) render their regular bills for Month B along with the actual surcharge applicable to Month B; or

(2) in the case of sale-for-resale transactions, render their regular bills for Month B along with a surcharge which consists of the net of:

(i) the projected incremental surcharge for Month B which was filed with the Commission and which was used in determining the "reduced PGA", and

(ii) the net difference between:

(A) the projected surcharge billed for Month A, and

(B) the actual surcharge payable, as computed in accordance with the regulations, for Month A.

(b) *Distributors may either:*

(1) render their regular bills for Month B along with the actual surcharge applicable to Month B; or

(2) render their regular bills for Month B, along with a surcharge which consists of the net of:

(i) the alternative fuel price ceiling, plus applicable taxes, applicable to the facility for Month B, and

(ii) the net difference between:

(A) the alternative fuel price ceiling, plus taxes, billed, and

(B) the actual surcharge payable, as computed in accordance with the regulations, for Month A.

16. On or about the 10th of Month D:

(a) Pipelines will render their next bills, computed in the manner prescribed above, and if they billed in the optional manner for sale-for-resale customers, they will net the difference between the estimated surcharge billed in Month C and the actual surcharge that should have been billed in Month C for Month B's consumption. This over or under amount billed in Month C will then be netted against the estimated surcharge billed in Month D.

(b) Distributors will render their next bills, computed in the manner prescribed above, and if they billed in the optional manner, they will net the difference between the alternative fuel price ceiling, plus taxes, billed in Month C and the actual surcharge that should have been billed in Month C for Month B's consumption. This over amount billed in Month C will then be netted against the alternative fuel price ceiling, plus taxes, billed on Month D.

(Natural Gas Act as amended, 15 U.S.C. 17 *et seq.*; the Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*; the Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267.)

In consideration of the foregoing, Title 18 of the Code of Federal Regulations is amended by revisions in Parts 154, 201, 204 and by the addition of a new Part 282, to read, in part, as set forth below.

By Direction of the Commission.

Lois D. Cashell,

Acting Secretary.

Appendix A

[Note.—This appendix will not appear in the Code of Federal Regulations.]

Federal Energy Regulatory Commission, Washington, D.C. 20426.

Exemptions From Incremental Pricing for Certain Categories of Industrial Boiler Fuel Use of Natural Gas.

Docket No. RM79-14.

Participation is Voluntary.

Copies of executed exemption affidavits filed with the Commission shall be available through the Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Please Read Before Completing This Affidavit.

Purpose

The Natural Gas Policy Act of 1978 (NGPA) provides that natural gas used as boiler fuel by any industrial boiler fuel facility will be subject to incremental pricing surcharges unless exempted. The statute provides for certain exemptions from these incremental pricing surcharges. To be wholly or partially exempt from incremental pricing surcharges the boiler fuel must be consumed for one of the statutorily exempt uses. This affadivit serves the purpose of identifying those natural gas uses within your facility which are entitled to a full or partial statutory exemption from incremental pricing surcharges but which could not be identified as exempt through review of the records of your natural gas supplier.

* * * * *

NOTICE

* * * * *

If you do not complete and return this affidavit setting forth your claim to a total or partial exemption, *ALL* gas sold to your facility will be subject to incremental pricing surcharges. Additionally, if circumstances or ownership change, you should immediately notify your natural gas supplier(s) of the change so that the correct amount of surcharge may be calculated as to your gas use or, if needed, you can complete a new exemption affidavit to obtain a new or changed exemption from the incremental pricing program. Failure to report changes can subject your facility to civil and criminal penalties under Section 504 of the Natural Gas Policy Act of 1978.

GENERAL INSTRUCTIONS

If you claim an exemption from incremental pricing surcharges for all, or a portion, of the gas used by your facility which has been identified by your natural gas supplier as a potentially non-exempt industrial boiler fuel facility, this affidavit should be completed and signed, under oath, by a responsible official associated with the facility. A separate affidavit must be filed for each facility for which a total or partial exemption from incremental pricing surcharges is claimed.

The original and five copies of this affidavit should be submitted to:

Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Also, one copy must be submitted to your natural gas supplier. Additionally, each industrial facility must retain such records, documents and data which formed the basis for the exemption claimed on this affidavit. Definitions which may be helpful in completing this affidavit are provided below.

If you have any questions concerning this affidavit contact Ms. Alice Fernandez on (202) 275-4406.

DEFINITIONS

(1) "Natural gas supplier" means an interstate pipeline or a local distribution company.

(2) "Local distribution company" means any person other than an interstate pipeline that receives gas directly or indirectly from an interstate pipeline and which is engaged in the sale of natural gas for resale or for ultimate consumption. A person is not considered as having received gas directly or indirectly from an interstate pipeline if the only service performed by an interstate pipeline for the purchaser is a transportation service.

(3) "Boiler fuel use" means the use of any fuel for the generation of steam or electricity.

(4) "Facility" means all buildings and equipment located at the same geographic site which are commonly considered to be part of one plant, mill, refinery, or other industrial complex.

(5) "Industrial facility" means any facility engaged primarily in the extraction or

processing of raw materials, or in the processing or changing of raw or unfinished materials into another form or product.

(6) "Industrial boiler fuel facility" means any industrial facility which uses natural gas as a boiler fuel.

(7) "Non-exempt industrial boiler fuel facility" means any industrial boiler fuel facility other than any such facility which has been exempted from the incremental pricing program in accordance with Part 282 of the Commission's rules and regulations.

(8) "Agricultural use" means any use of natural gas (a) which is certified by the Secretary of Agriculture under 7 CFR 2900.3 as an "essential agricultural use" pursuant to section 401(c) of the NGPA; or (b) which is used in the following textile manufacturing operations, limited as set forth below to the production or processing of natural fiber, as set forth in the *Standard Industrial Classification Manual—1972:*

Industry Sic No. and Industry Description—

220—Broad Woven Fabric Mills, Cotton.
222—Broad Woven Fabric Mills, Man-made Fiber and Silk (natural fiber processing only).
223—Broad Woven Fabric Mills, Wool (Including Dyeing and Finishing).
224—Narrow Fabrics and Other Smallwares Mills: Cotton, Wool, Silk, and Man-made Fiber (natural fiber processing only).
2257—Circular Knit Fabric Mills (natural fiber processing only).
2258—Warp Knit Fabric Mills (natural fiber processing only).
226—Dyeing and Finishing Textiles, Except Wool Fabrics and Knit Goods (natural fiber processing only).
228—Yarn and Thread Mills (natural fiber processing only).
2291—Felt Goods, Except Woven Felts and Hats (natural fiber processing only).
2293—Paddings and Upholstery Filling (natural fiber processing only).
2294—Processed Waste and Recovered Fibers and Flock (natural fiber processing only).
2295—Coated Fabric, Not Rubberized (natural fiber processing only).
2297—Nonwoven Fabrics (natural fiber processing only).
2299—Textile Goods, Not Elsewhere Classified (natural fiber processing only).

(9) "School" means a facility the primary function of which is the delivery of instruction to regularly enrolled students in attendance at such facility. Facilities used for both educational and non-educational activities are not included under this definition unless the latter activities are merely incidental to the delivery of instruction.

(10) "Hospital" means a facility the primary function of which is the delivery of medical care to patients who remain at the facility. Outpatient clinics or doctor's offices are not included in this definition. Nursing homes and convalescent homes are included in this definition.

(11) "Similar institution" means a facility the primary function of which is the same as the primary function of the facility to which it is compared.

(12) "Qualifying cogeneration facility" means a cogeneration facility which meets the requirements prescribed by the Commission pursuant to section 201 of the Public Utility Regulatory Policies Act of 1978.

BILLING CODE 6450-01-M

1.0 Name of Company or Organization: ____________

____

2.0 Name of Facility: ____________

* * *

3.0 Address: ____________
Number Street

____
City/Town County State Zip Code

* * *

4.0 Name of Natural Gas Supplier: ____________

____

____

* * *

5.0 Is your facility an "industrial boiler fuel facility", as defined in the "Definitions" of this affidavit?

(a) ☐ No ... Sign and return affidavit.

(b) ☐ Yes ... Continue to 6.0.

* * *

6.0 Was your facility in existence on November 9, 1978, and did your facility, on the basis of records, documents or data in your possession, consume no more than an average of 300 Mcf per day as boiler fuel during any calendar month of calendar year 1977?

(a) ☐ Yes ... Sign and return affidavit.

(b) ☐ No ... Continue to 7.0.

* * *

7.0 Is all of the natural gas consumed as boiler fuel at your facility for an agricultural use?

(a) ☐ Yes ... Sign and return affidavit.

(b) ☐ No ... Continue to 8.0.

* * *

8.0 Is your facility, in its entirety, any of the following:

(a) A school, hospital, or similar facility?

☐ Yes ☐ No

(b) Used for generation of electricity by an electric generation station owned by an electric utility?

☐ Yes ☐ No

(c) A qualifying co-generation facility?

☐ Yes ☐ No

If the answer is "yes" to any of the above, sign and return this affidavit. If the answer is "no", continue to 9.0.

* * *

9.0 Is a portion, though not all, of the gas consumed at your facility used as boiler fuel for an agricultural use?

(a) ☐ Yes ... See "NOTICE" below.

(b) ☐ No ... Continue to 10.0.

* * *

10.0 Is your facility, in part, but not in its entirety, any of the following:

(a) A school, hospital, or similar facility?

☐ Yes ☐ No

(b) Used for the generation of electricity by an electric generation station owned by an electric utility?

☐ Yes ☐ No

(c) A qualifying co-generation facility?

☐ Yes ☐ No

If the answer is "yes" to any of the above, see "NOTICE" below, sign and return this affidavit. If the answer is "no" to all questions in items 6.0 through 10.0, you should not return this affidavit.

* * *

NOTICE

If you have responded affirmatively to question 9.0, the volume of natural gas used in your facility which shall be exempt from incremental pricing: (1) for the period January 1, 1980, through October 31, 1980, may be determined on the basis of submetering determinations, monthly estimates which are certified by a responsible company official or on the basis of an agreement executed by you and your natural gas supplier; and (2) for the period beginning November 1, 1980, shall be determined on the basis of and to the extent there are submeter reading records for each calendar month, as signed under oath by a responsible company official, which show the extent to which gas is consumed for an agricultural use and which are furnished to the facility's natural gas supplier as required by the supplier. Certified monthly estimates or the agreement with your supplier may be utilized for a period following November 1, 1980, if you have obtained a purchase order for all submeters which will be needed in your facility by November 1, 1980, and expect installation within a reasonable time period.

If you have responded affirmatively to any part of question 10.0, the volume of natural gas which shall be exempt from incremental pricing: (1) for the period January 1, 1980, through October 31, 1980; may be determined on the basis of submetering determinations, monthly estimates which are certified by a responsible company official or on the basis of an agreement executed by you and your natural gas supplier; and (2) for the period beginning November 1, 1980, shall be determined on the basis of and to the extent there are submeters which permit determination of the volume of exempt usage and which are available to be read by the facility's natural gas supplier, or on the basis of and to the extent there are submeter reading records for each month, as signed under oath by a responsible company official, which show the extent to which gas is consumed for an exempt use and which are furnished to the facility's natural gas supplier as required by the supplier. Certified monthly estimates or the agreement with your supplier may be utilized for a period following November 1, 1980, if you have obtained a purchase order for all submeters which will be needed in your facility by November 1, 1980, and expect installations within a reasonable time period.

DATED: ____________________

Person completing this affidavit:

____
Name

____
Title

____
Phone number

Subscribed and sworn to before me this ______ day of ____________.

____
Notary Public

BILLING CODE 6450-01-C

PART 154—RATE SCHEDULES AND TARIFFS

1. Section 154.38 is amended in paragraph (d) by revising subparagraph (1) and clause (iv)(*a*) of subparagraph (4) to read as follows:

§ 154.38 Composition of rate schedule.

* * * * *

(d) *Statement of rate.* (1) Except as permitted in § 154.52, § 154.82 and Part 282, all rates shall be clearly stated in cents or in dollars and cents per unit. Only the rates and charges to be used in current billing shall be included in the rate schedules. * * *

(4) * * *

(iv)(*a*) Rate changes which reflect both the projected cost of purchased gas and a revised surcharge to clear the amounts accrued in the deferred account for both producer and pipeline suppliers shall be computed and filed not more frequently than semi-annually. Pipeline companies may reflect in their rates such changes as are permitted to producers of natural gas under the Natural Gas Policy Act of 1978. Pipeline companies with semi-annual adjustment dates may not reflect in their purchased gas pattern any supply which is not attached to its system as of the effective date of the proposed rate change. * * *

* * * * *

PART 201—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR NATURAL GAS COMPANIES SUBJECT TO THE PROVISIONS OF THE NATURAL GAS ACT (CLASS A AND CLASS B)

2. Part 201, account 191 is amended by revising paragraph A to read as follows:

191 Unrecovered purchased gas costs.

A. This account shall include purchased gas costs related to Commission approved purchased gas adjustment clauses when such costs are not included in the utility's rate schedules on file with the Commission. This account shall also include such other costs as authorized by the Commission. Costs of purchased gas subject to passthrough under the incremental pricing requirements of the Commission shall be excluded from this account and included in account 192.1, Unrecovered Incremental Gas Costs.

* * * * *

3. Part 201 is amended to add a new account 192.1 to read as follows:

192.1 Unrecovered incremental gas costs.

A. This account shall include the unrecovered costs of purchased gas which are subject to passthrough by means of an incremental pricing surcharge. This account shall also include any other costs authorized by the Commission.

B. This account shall be debited and account 805.2, Incremental Gas Cost Adjustments, shall be credited for unrecovered costs of purchased gas subject to incremental pricing.

C. This account shall be credited and account 805.2 debited for those costs included in this account which are passed through by means of incremental pricing surcharges.

D. Those costs accumulated in this account for gas received during a calendar month which are not subject to passthrough by incremental pricing surcharges because of alternative fuel price ceilings shall be transferred to account 191, Unrecovered Purchased Gas Costs, no later than the end of the month in which the applicable surcharges are billed.

E. Separate subaccounts shall be maintained for the accumulation of incremental gas costs each calendar month and the passthrough or transfer of such costs so as to keep each period separate.

4. Part 201 is amended to add a new account 192.2 to read a follows:

192.2 Unrecovered incremental surcharges.

A. This account shall include any incremental pricing surcharges passed through to the company by pipeline suppliers.

B. This account shall be debited and account 805.2, Incremental Gas Cost Adjustments, shall be credited with the amount of each incremental pricing surcharge as incurred.

C. This account shall be credited and account 805.2 shall be debited with the amounts included in this account which are passed through to customers.

5. Part 201 is amended to add a new account 805.2 to read as follows:

805.2 Incremental gas cost adjustments.

A. This account shall be credited with the costs of purchased gas which are subject to passthrough by means of incremental pricing surcharges.

B. This account shall also be credited with any incremental pricing surcharges passed through to the company by pipeline suppliers.

C. This account shall be debited with amounts from account 192.1, Unrecovered Incremental Gas Costs, which are passed through by means of incremental pricing surcharges.

D. This account shall also be debited with amounts from account 192.2, Unrecovered Incremental Surcharges, which are passed through by means of incremental pricing surcharges.

PART 204—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR NATURAL GAS COMPANIES SUBJECT TO THE PROVISIONS OF THE NATURAL GAS ACT (CLASS C AND CLASS D)

6. Part 204, account 191 is amended by revising paragraph A to read as follows:

191 Unrecovered purchased gas costs.

A. This account shall include purchased gas costs related to Commission approved purchased gas adjustment clauses when such costs are not included in the utility's rate schedules on file with the Commission. This account shall also include such other costs as authorized by the Commission. Costs of purchased gas subject to passthrough under the incremental pricing requirements of the Commission shall be excluded from this account and included in account 192.1, Unrecovered Incremental Gas Costs.

* * * * *

7. Part 204 is amended to add a new account 192.1 to read as follows:

192.1 Unrecovered incremental gas costs.

A. This account shall include the unrecovered costs of purchased gas which are subject to passthrough by means of incremental pricing surcharges. This account shall also include any other costs authorized by the Commission.

B. This account shall be debited and account 731.2, Incremental Gas Cost Adjustments, shall be credited for unrecovered costs of purchased gas subject to incremental pricing.

C. This account shall be credited and account 731.2 debited for those costs included in this account which are passed through by means of incremental pricing surcharges.

D. Those costs accumulated in this account for gas received during a calendar month which are not subject to passthrough by incremental pricing surcharges because of alternative fuel price ceilings shall be transferred to account 191, Unrecovered Purchased Gas Costs, no later than the end of the month in which the applicable surcharges are billed.

E. Separate subaccounts shall be maintained for the accumulation of incremental gas costs each calendar month and the passthrough or transfer of such costs so as to keep each period separate.

8. Part 204 is amended to add a new account 192.2 to read as follows:

192.2 Unrecovered incremental surcharges.

A. This account shall include any incremental pricing surcharges passed through to the company by its pipeline suppliers.

B. This account shall be debited and account 731.2, Incremental Gas Cost Adjustments, shall be credited with the amount of each incremental pricing surcharge as incurred.

C. This account shall be credited and account 731.2 shall be debited with the amounts included in this account which are passed through to customers.

9. Part 204 is amended to add a new account 731.2 to read as follows:

731.2 Incremental gas cost adjustments.

A. This account shall be credited with the costs of purchased gas which are subject to passthrough by means of incremental pricing surcharges.

B. This account shall also be credited with any incremental pricing surcharges passed through to the company by its pipeline suppliers.

C. This account shall be debited with amounts from account 192.1, Unrecovered Incremental Gas Costs, which are passed through by means of incremental pricing surcharges.

D. This account shall also be debited with amounts from account 192.2, Unrecovered Incremental Surcharges, which are passed through by means of incremental pricing surcharges.

10. Subchapter I of Chapter I is amended by adding a new Part 282 to read as follows:

PART 282—INCREMENTAL PRICING

Authority: This part is issued under the Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*

Subpart A—General Rules and Definitions

§ 282.101 Purpose.

The purpose of this part is to set forth an incremental pricing rule in accordance with Title II of the Natural Gas Policy Act of 1978. The rule requires that certain costs of acquiring natural gas be passed through as a surcharge on sales of natural gas used as specified in the rule.

§ 282.102 Applicability and effective date.

(a) *Uses.* Natural gas used as boiler fuel in industrial boiler fuel facilities on and after January 1, 1980, shall be subject to incremental pricing under this part.

(b) *Costs.* Costs described in Subpart C and incurred by natural gas suppliers on or after January 1, 1980, shall be subject to this part.

(c) *Natural gas suppliers.* Interstate pipelines and local distribution companies shall be subject to this part.

(d) *Effective date.* The provisions of this part shall be effective November 1, 1979, *provided that* the provisions of §§ 282.201 through 282.206 shall be effective October 15, 1979.

§ 282.103 Definitions.

For purposes of this part: (a) "Natural gas supplier" means an interstate pipeline or a local distribution company.

(b) "Local distribution company" means any person other than an interstate pipeline that receives gas directly or indirectly from an interstate pipeline and which is engaged in the sale of natural gas for resale or for the ultimate consumption. A person is not considered as having received gas directly or indirectly from an interstate pipeline if the only service performed by an interstate pipeline for the purchaser is a transportation service.

(c) "Facility" means all buildings and equipment located at the same geographic site which are commonly considered to be part of one plant, mill, refinery or other industrial complex.

(d) "Industrial facility" means any facility engaged primarily in the extraction or processing of raw materials, or in the processing or changing of raw or unfinished materials into another form or product.

(e) "Non-exempt industrial boiler fuel facility" means any industrial boiler fuel facility other than any such facility which has been exempted from the provisions of this part in accordance with Subpart B.

(f) "No. 2 fuel oil" means No. 2 oil as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM D 396-78.

(g) "No. 5 fuel oil" means either light or heavy No. 5 oil as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM D 396-78.

(h) "No. 6 fuel oil" means No. 6 oil as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM D 396-78.

(i) "Low sulfur fuel oil" means any oil containing 1 percent (1%) or less sulfur content by weight.

(j) "High sulfur fuel oil" means any oil containing more than 1 percent (1%) sulfur content by weight.

(k) "British thermal unit" or "Btu" shall have the meaning set forth in § 270.102.

Subpart B—Exemptions

§ 282.201 General rule.

(a) *Statutory exemptions.* Natural gas used for purposes described in § 282.203 shall be exempt from incremental pricing as provided in subsections 206 (a), (b) and (c) of the NGPA. Exemptions for such gas may be obtained in the manner prescribed in § 282.204. Adjustments under authority of subsection 502(c) of the NGPA as may be necessary to prevent special hardship, inequity, or unfair distribution of burdens may be obtained as provided in § 1.41.

(b) *Discretionary exemptions.* Petitions for an exemption under authority of subsection 206(d) of the NGPA may be filed in the manner prescribed in § 282.206.

§ 282.202 Definitions.

For the purposes of this subpart:

(a) "Agricultural use" means any use of natural gas:

(1) which is certified by the Secretary of Agriculture under 7 CFR § 2900.3 as an "essential agricultural use" pursuant to section 401(c) of the NGPA; or

(2) which is used in the following textile manufacturing operations limited as set forth below to the production or processing of natural fiber, as set forth

in the *Standard Industrial Classification Manual—1972:*

Industry SIC No. and Industry Description

221 Broad Woven Fabric Mills, Cotton
222 Broad Woven Fabric Mills, Man-made Fiber and Silk (natural fiber processing only)
223 Broad Woven Fabric Mills, Wool (Including Dyeing and Finishing)
224 Narrow Fabrics and Other Smallwares Mills: Cotton, Wool, Silk, and Man-made Fiber (natural fiber processing only)
2257 Circular Knit Fabric Mills (natural fiber processing only)
2258 Warp Knit Fabric Mills (natural fiber processing only)
226 Dyeing and Finishing Textiles, Except Wool Fabrics and Knit Goods (natural fiber processing only)
228 Yarn and Thread Mills (natural fiber processing only)
2291 Felt Goods, Except Woven Felts and Hats (natural fiber processing only)
2293 Paddings and Upholstery Filling (natural fiber processing only)
2294 Processed Waste and Recovered Fibers and Flock (natural fiber processing only)
2295 Coated Fabric, Not Rubberized (natural fiber processing only)
2297 Nonwoven Fabrics (natural fiber processing only)
2299 Textile Goods, Not Elsewhere Classified (natural fiber processing only)

(b) "School" means a facility the primary function of which is the delivery of instruction to regularly enrolled students in attendance at such facility. Facilities used for both educational and non-educational activities are not included under this definition unless the latter activities are merely incidental to the delivery of instruction.

(c) "Hospital" means a facility the primary function of which is the delivery of medical care to patients who remain at the facility. Outpatient clinics or doctor's offices are not included in this definition. Nursing homes and convalescent homes are included in this definition.

(d) "Similar institution" means a facility the primary function of which is the same as the primary function of the facility to which it is compared.

(e) "Qualifying cogeneration facility" means a cogeneration facility which meets the requirements prescribed by the Commission pursuant to section 201 of the Public Utility Regulatory Policies Act of 1978.

§ 282.203 Exempt end-uses.

The incremental pricing provisions of this part shall only apply to industrial facilities which use natural gas as a boiler fuel. In addition, in accordance with the provisions of sections 206 (a), (b), and (c) of the NGPA, natural gas used for the following purposes shall be exempt from incremental pricing under this part:

(a) all gas used for boiler fuel by an industrial boiler fuel facility which was:

(1) in existence on November 9, 1978; and

(2) did not consume more than an average of 300 Mcf per day for boiler fuel during any calendar month of calendar year 1977;

(b) all gas used for an agricultural use;

(c) all gas used in a school, hospital, or similar institution;

(d) all gas used for the generation of electricity by an electric utility; and

(e) all gas used in a qualifying cogeneration facility.

§ 282.204 Obtaining an exemption.

(a) *General.* This section establishes procedures by which owners or operators of industrial boiler fuel facilities may obtain an exemption for natural gas used for the purposes described in § 282.203.

(b) *Determination of industrial boiler fuel facilities.* On or before October 15, 1979, each natural gas supplier shall determine which facilities served directly by it are industrial boiler fuel facilities.

(c) *Exemption on the basis of company records.* (1) On or before October 15, 1979, each natural gas supplier shall determine from an examination of its records which industrial boiler fuel facilities, as identified under paragraph (b), were in existence on November 9, 1978, and either:

(i) did not use more than an average of 300 Mcf per day during any calendar month of calendar year 1977; or

(ii) did not use more than an average of 300 Mcf per day for boiler fuel during any calendar month of calendar year 1977.

(2) The natural gas supplier shall treat an industrial boiler fuel facility for which an affirmative determination is made under subparagraph (1) as exempt from incremental pricing under this part without further action by the owner or operator of the facility.

(d) *Exemption on the basis of affidavit.* (1) *Commission to provide exemption affidavits.* On and after October 3, 1979, exemption affidavits as described in subparagraph (3) will be available to natural gas suppliers for purposes of subparagraph (2) and to any other interested person upon request from the Office of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(2) *Availability from natural gas suppliers.* (i) *Initial service.* Not later than October 15, 1979, each natural gas supplier shall mail or otherwise supply an exemption affidavit, as described in subparagraph (3), to the owner or operator of each industrial boiler fuel facility on such natural gas supplier's system which the natural gas supplier did not determine to be exempt pursuant to paragraph (c).

(ii) *Response date.* Natural gas suppliers which supply exemption affidavits under clause (i) shall request that executed affidavits be filed on or before November 1, 1979, in accordance with subparagraph (4).

(iii) *Ongoing availability.* After October 15, 1979, natural gas suppliers shall make exemption affidavits available at their principal place of business on an ongoing basis during regular business hours.

(3) *Contents of exemption affidavit.* (i) The exemption affidavit will provide the owner or operator of an industrial boiler fuel facility with the opportunity to respond to the following questions:

(A) Was the customer's facility in existence on November 9, 1978, and did the facility, on the basis of records, documents, or data in the customer's possession, consume no more than an average of 300 Mcf per day as boiler fuel during any calendar month of calendar year 1977?

(B) Is all of the natural gas consumed at the customer's facility used as boiler fuel for an agricultural use?

(C) Is the customer's facility, in its entirety, a school, hospital, or similar facility?

(D) Is the customer's facility, in its entirety, used for the generation of electricity by an electric utility?

(E) Is the customer's facility, in its entirety, a qualifying cogeneration facility?

(F) Is a portion, though not all, of the gas consumed at the customer's facility used as boiler fuel for an agricultural use?

(G) Is the customer's facility, in part but not in its entirety, a school, hospital, or similar facility?

(H) Is the customer's facility, in part but not in its entirety, used for the generation of electricity by an electric utility?

(I) Is the customer's facility, in part but not in its entirety, a qualifying cogeneration facility?

(ii) The exemption affidavit will notify the customer that, if he affirmatively responds to any of the questions (F) through (I) volumes of natural gas used in the customer's facility will be exempt from incremental pricing to the extent that:

(A) For the period prior to November 1, 1980, the customer provides submetering determinations or certified estimates on a monthly basis to his supplier or executes an agreement with his supplier so as to establish the volumes of natural gas used in his facility which will be exempt from incremental pricing; and

(B) On and after November 1, 1980, the customer maintains submeters and records, or obtains a purchase order for submeters as required by subparagraph (6).

(iii) The exemption affidavit will indicate the record retention obligation which may be incurred by the customer under subparagraph (8) of this paragraph.

(iv) The exemption affidavit will contain such other information as may be necessary for completion and return of the affidavit.

(4) *Filing of exemption affidavits.* In order to obtain an exemption from incremental pricing, an owner or operator of an industrial boiler fuel facility shall file an executed exemption affidavit, signed and dated by a responsible official associated with the facility, under oath, with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C., 20426, and send a copy of the executed affidavit to the natural gas supplier serving the industrial boiler fuel facility.

(5) *Effect of filing an exemption affidavit.* (i) If the owner or operator of an industrial boiler fuel facility affirmatively responds to any of the questions (A) through (E), as set out in subparagraph (3), and files the affidavit in accordance with subparagraph (4), then natural gas used in the facility shall be exempt from incremental pricing under this part.

(ii) If the owner or operator of an industrial boiler fuel facility affirmatively responds to any of the questions (F) through (I) as set out in subparagraph (3); and files the affidavit in accordance with subparagraph (4), then natural gas used in the industrial boiler fuel facility shall be exempt from incremental pricing to the extent determined in accordance with the applicable provision of subparagraph (6).

(6) *Determination of extent of partial exemption.* (i) If the owner or operator of an industrial boiler fuel facility affirmatively responds to question (F) as set out in subparagraph (3):

(A) For the period January 1, 1980, through October 31, 1980, the volume of natural gas used in the facility which shall be exempt from incremental pricing may be determined monthly on the basis of:

(*1*) submetering determinations;

(*2*) estimates, as signed under oath by a responsible company official, that are furnished to the facility's natural gas supplier as required by the supplier for billing purposes; or

(*3*) a supplier-customer agreement, signed by responsible officials of the supplier and the customer, as to the volume of natural gas which is consumed by the customer for an agricultural use.

(B)(*1*) Subject to clause (*2*), on and after November 1, 1980, the volume of natural gas used in the facility which shall be exempt from incremental pricing shall be determined on the basis of and to the extent there are submeter reading records for each month, as signed under oath by a responsible company official, that show the extent to which gas is consumed for an agricultural use and that are furnished to the facility's natural gas supplier as required by the supplier for billing purposes.

(*2*) Certified monthly estimates or a supplier-customer agreement may be utilized to determine the volume of natural gas consumed in the facility for an agricultural use which shall be exempt from incremental pricing for a period following November 1, 1980, *provided that* the owner or operator of the facility has obtained a purchase order for all submeters which will be needed in the facility by November 1, 1980, and such submeters will be installed within a reasonable period of time.

(ii) If the owner or operator of an industrial boiler fuel facility affirmatively responds to any of the questions (G) through (I):

(A) For the period January 1, 1980, through October 31, 1980, the volume of natural gas used in the facility which shall be exempt from incremental pricing may be determined monthly on the basis of:

(*1*) submetering determinations;

(*2*) estimates, as signed under oath by a responsible company official, for each month that are furnished to the facility's natural gas supplier as required by the supplier for billing purposes; or

(*3*) a supplier-customer agreement signed by responsible officials of the supplier and the customer, as to the volume of natural gas which is consumed by the customer for an exempt use.

(B)(*1*) Subject to clause (*2*), on and after November 1, 1980, the volume of natural gas used in the facility which shall be exempt from incremental pricing shall be determined on the basis of and to the extent there are submeters which permit determination of the volume of exempt usage and which are available to be read by the facility's natural gas supplier, or on the basis of and to the extent there are submeter reading records for each month, as signed under oath by a responsible company official, that show the extent to which gas is consumed for an exempt use and that are furnished to the facility's natural gas supplier as required for billing purposes.

(*2*) Certified monthly estimates or a supplier-customer agreement may be utilized to determine the volume of natural gas consumed in the facility for an exempt use which shall be exempt from incremental pricing for a period following November 1, 1980, *provided that* the owner or operator of the facility has obtained a purchase order for all submeters which will be needed in the facility by November 1, 1980, and such submeters will be installed within a reasonable period of time.

(7) *Effective date of exemption.* (i) If the owner or operator of an industrial boiler fuel facility files an exemption affidavit with the Commission and sends a copy to the facility's natural gas supplier in accordance with subparagraph (4) on or before December 31, 1979, the facility shall be exempt from incremental pricing in accordance with this part as of January 1, 1980.

(ii) If the owner or operator of an industrial boiler fuel facility files an exemption affidavit with the Commission and sends a copy to the facility's natural gas supplier in accordance with subparagraph (4) on or after January 1, 1980, the facility shall be exempt from incremental pricing under this part as of the beginning of the first full month following the date the exemption affidavit is filed with the Commission and received by the facility's natural gas supplier.

(8) *Record retention.* If the owner or operator of an industrial boiler fuel facility obtains an exemption as a result of affirmatively responding to question (A) as set out in subparagraph (3), the owner or operator shall, for a period of at least three years from the date of filing the exemption affidavit, retain all records, documents or data which formed the basis of the response.

(e) *Public availability of exemption information.* (1) *Executed exemption affidavits.* Copies of executed exemption affidavits which are filed with the Commission shall be available for public inspection through the Office of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(2) *Lists of non-exempt facilities.* (i) On or before January 15, 1980, each natural gas supplier shall file with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and with

each state or local regulatory authority having appropriate jurisdiction over the supplier, a list of all industrial boiler fuel facilities served directly by the supplier which did not qualify for an exemption under paragraph (c) or (d) as of December 31, 1979.

(ii) On or before January 15th of each year after 1980, each natural gas supplier shall file with the agencies specified in clause (i) a revised list of all non-exempt industrial boiler fuel facilities served directly by the supplier. A revised list shall indicate all additions or revisions to or deletions from the prior year's list.

(iii) Lists of non-exempt industrial boiler fuel facilities filed in accordance with clause (i) or (ii) shall indicate the alternative fuel capability of each facility thereon, as established in accord with the provisions of § 282.403.

(iv) Lists of non-exempt facilities filed in accordance with clause (i) or (ii) shall be available for public inspection through the Office of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(f) *Protests.* (1) Any interested person may protest the exemption of an industrial boiler fuel facility from incremental pricing.

(2) The procedures set forth in § 1.10 shall govern the filing of such a protest, except that any person filing such a protest shall serve a copy of the protest on the affiant of the exemption affidavit.

(3) The affiant may file an answer to any protest. Such answer must be filed within 30 days of the service date of a protest. The affiant shall serve a copy of the answer on the party filing the protest.

§ 282.205 Change of circumstances.

(a) *General rule.* (1) If circumstances change with respect to any facility which has been exempt in whole or in part from the provisions of this part such that the basis for the exemption has changed or no longer exists, the owner or operator of such facility shall promptly, in writing, under oath, notify the Commission and the natural gas supplier serving the facility that the basis for the exemption has changed or no longer exists. In such case, the natural gas used in the facility shall be subject to incremental pricing surcharges in accordance with and to the extent required by the provisions of this part.

(2) Such notification shall be marked, "Change of Exemption Status under Incremental Pricing Program" and shall be filed with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(3) A notification filed pursuant to subparagraph (1) shall be effective as of the beginning of the first full month of service after the notification is filed with the Commission and is received by the natural gas supplier serving the facility.

§ 282.206 Petitions for exemptions under section 206(d).

(a) *General rule.* Any person may petition under authority of subsection 206(d) of the NGPA for the exemption, in whole or in part, of any non-exempt industrial boiler fuel facility or category thereof.

(b) *Filing requirements.* A petition for an exemption under authority of subsection 206(d) shall:

(1) conform to the requirements of § 1.7;

(2) contain sufficient information and data to permit review of the petition on the merits; and

(3) provide an analysis of any environmental issues which are relevant to the request for an exemption.

(c) *Notice.* Public notice of the filing of a petition for an exemption under authority of subsection 206(d) shall be given with opportunity for comment by interested persons.

(d) *Denial without prejudice.* A petition for an exemption under authority of subsection 206(d) which is not acted upon within 90 days of the date for submission of comments shall be deemed denied without prejudice.

Subpart C—Determination of Costs Subject to Incremental Pricing

§ 282.301 Costs subject to incremental pricing.

The costs specified in this section are acquisition costs which shall be subject to the passthrough provisions of this part.

(a) *New natural gas.* In the case of new natural gas (as defined in section 102(c) of the NGPA), any portion of the first sale acquisition cost of such natural gas which exceeds the incremental pricing threshold applicable for the month in which the delivery of such natural gas occurs shall be subject to this part.

(b) *Natural gas under intrastate rollover contract.* In the case of natural gas delivered under a rollover contract which was not committed or dedicated to interstate commerce on November 8, 1978, any portion of the first sale acquisition cost of such natural gas which exceeds the incremental pricing threshold applicable for the month in which the delivery occurs shall be subject to this part.

(c) *New, onshore production well gas.* In the case of natural gas produced from any new, onshore production well (as defined in section 103(c) of the NGPA), any portion of the first sale acquisition cost of such natural gas which exceeds the incremental pricing threshold applicable for the month in which the delivery of such natural gas occurs shall be subject to this part.

(d) *LNG imports.* (1) Subject to the provisions in subparagraph (2), in the case of liquefied natural gas imported into the United States, any portion of the first sale acquisition cost of such natural gas (whether or not liquefied when acquired) which exceeds the incremental pricing threshold applicable for the month in which such liquefied natural gas enters the United States shall be subject to this part.

(2) Costs of liquefied natural gas imported into the United States shall not be subject to this part if:

(i) the importation of the liquefied natural gas was authorized under section 3 of the Natural Gas Act on or before May 1, 1978;

(ii) an application for such authority was pending under section 3 of the Natural Gas Act on such date, except as set forth in subparagraph (3) below; or

(iii) in connection with the granting of any authority under the Natural Gas Act to import such liquefied natural gas, the Secretary of the Department of energy or the Commission, in accordance with the Department of Energy Organization Act (or any delegation or assignment thereunder), determines that a contract binding on the importer or other substantial financial commitment of the importer was made on or before such date, except as set forth in subparagraph (3) below.

(3) Clauses (ii) and (iii) of subparagraph (2) shall not apply with respect to any liquefied natural gas imports if, in connection with the granting of any authority under the Natural Gas Act to import such liquefied natural gas, the Secretary of the Department of Energy or the Commission, in accordance with the assignment of functions under the Department of Energy Organization Act, determines that the portion of the costs of such imports as described in subparagraph (1) shall be subject to this part.

(e) *Natural gas (other than LNG) imports.* (1) Subject to subparagraph (2), in the case of natural gas (other than liquefied natural gas) imported into the United States, any portion of the first sale acquisition cost of such imported natural gas which exceeds the maximum lawful price, per million Btu's, computed under section 102 of the NGPA (relating to new natural gas) for the month in which such natural gas enters the United States without regard to section 110 of the NGPA, shall be subject to this part.

(2) Subject to subparagraph (3), subparagraph (1) shall only apply to costs of volumes of natural gas (other than liquefied natural gas) imported into the United States which exceed both:

(i) the maximum delivery obligations for the month in which such delivery of natrual gas occurs, as specified by contracts entered into on or before May 1, 1978 and in effect when such delivery occurs; and

(ii) the volume of natural gas imported into the United States by the interstate pipeline involved during the corresponding month of calendar year 1977.

(3) Subparagraph (2) notwithstanding, subparagraph (1) shall apply to the portion of first sale acquisition costs, as described in subparagraph (1), of volumes of natural gas (other than liquefied natural gas) imported into the United States which exceed the volume of natural gas imported into the United States by the interstate pipeline involved during calendar year 1977 if, in connection with the granting of any authority under the Natural Gas Act to import such natural gas, the Secretary of the Department of Energy or the Commission, in accordance with the assignment of functions under the Department of Energy Organization Act, determines that subparagraph (1) shall apply with respect to such natural gas imports.

(f) *Stripper well natural gas.* In the case of stripper well natural gas (as defined in section 108(b) of the NGPA), any portion of the first sale acquisition cost of such natural gas which exceeds the maximum lawful price, per million Btu's, computed under section 102 of the NGPA (relating to new natural gas) for the month in which the delivery of such gas occurs without regard to section 110 of the NGPA, shall be subject to this part.

(g) *High-cost natural gas.* In the case of high-cost natural gas (as defined in section 107(c) of the NGPA), any portion of the first sale acquisition cost of such natural gas which exceeds 130 percent of—

(1) the weighted average per barrel cost of No. 2 fuel oil landed in the greater New York City metropolitan area, as published by the Energy Information Administration of the Department of Energy, during the month preceding the month in which delivery of such natural gas occurs, divided by,

(2) a Btu conversion factor of 5.8 million Btu's per barrel—shall be subject to this part.

(h) *Alaska Natural Gas Transportation System*: In the case of natural gas produced from the Prudhoe Bay Unit of Alaska (as defined in section 2 of the NGPA), and transported through the natural gas transportation system approved under the Alaska Natural Gas Transportation Act of 1976, the following amounts shall be subject to this part:

(1) any portion of the first sale acquisition cost of natural gas which is not described in subparagraph (2) and which exceeds the maximum lawful price, per million Btu's computed under section 109 of the NGPA (relating to other categories of natural gas) for the month in which delivery of such natural gas occurs without regard to section 110 of the NGPA; and

(2) any amount paid to any person (other than the producer of such natural gas or an affiliate of such producer) for, or attributable to, any compressing, gathering, processing, treating, liquefying, or transporting of such natural gas, or any similar service provided with respect to such natural gas, before the delivery of such natural gas to such system.

(i) *Increased state severance taxes.* (1) Subject to the provisions of subparagraph (2), any portion of the cost of natural gas at any first sale attributable to any increase in the amount of state severance taxes (as defined in section 110(c) of the NGPA) which results from a provision of state law enacted on or after December 1, 1977, shall be subject to this part.

(2) Subparagraph (1) shall not apply to any increase in state severance taxes resulting from a change in the method of computation of such tax by reason of any provision of state law enacted on or after December 1, 1977, if:

(i) as of the effective date of such change in method of computation, such increase does not result in an increase in the level of such tax, expressed as a percentage of the weighted average first sale price of natural gas produced in such state, above the percentage of such average first sale price which such tax constituted on the day before such effective date; and

(ii) such provision of law is equally applicable to natural gas produced in the state and delivered to interstate commerce and to natural gas produced in the state and not so delivered.

(3) The price to be used in determining the weighted average first sale price for purposes of subparagraph (2) shall be the price paid at the first sale which is used by the state in administering such tax (or an imputed value, if the state uses an event other than a first sale in administering such tax).

(j) *Transactions under section 311(b) of the NGPA.* In the case of any sale under section 311(b) of the NGPA by an intrastate pipeline to an interstate pipeline or a local distribution company, any portion of the amount paid, per million Btu's, by the purchaser to the intrastate pipeline which exceeds the incremental pricing threshold for the month in which the acquisition of the natural gas occurs shall be subject to this part.

(k) *Pipeline produced gas.* (1) In the case of any natural gas produced by an interstate pipeline which is priced in its overall cost of service, without regard to the cost of producing the gas, any portion of the first sale acquisition cost imputed under § 282.303 shall be subject to this part if it would have been subject to this part under paragraphs (a) through (h) had the gas been produced by an independent producer and purchased by the interstate pipeline at the imputed level.

(2) Gas produced by an interstate pipeline which is treated, for rate purposes, on a cost of service basis and which is not acquired by the interstate pipeline in a first sale shall not be subject to this part.

(3) Costs of gas produced by producers affiliated with interstate pipelines shall be treated as costs incurred for production by an independent producer and shall be subject to this part, except to the extent that sale of such gas is not treated as a first sale under the NGPA.

(l) *Surcharges paid to other pipelines.* The amount of any incremental pricing surcharge (described in § 282.504) paid by any interstate pipeline for natural gas acquired by such pipeline from another pipeline shall be subject to this part.

§ 282.302 Gas qualifying under more than one provision.

If natural gas qualifies under more than one paragraph of § 282.301, the paragraph which reflects the highest threshold shall be applicable for purposes of determining the portion of the first sale acquisition costs of such natural gas which shall be subject to passthrough under this part.

§ 282.303 First sale acquisition cost.

(a) *General rule.* For purposes of this part, the first sale acquisition cost of natural gas is:

(1) the price paid, per million Btu's, in any first sale of such natural gas, in the case of any natural gas produced in the United States and acquired in such first sale; or

(2) the price paid for such natural gas, per million Btu's, at the point of entry to the United States, in the case of natural gas or liquefied natural gas imported into the United States.

(b) *State serverance taxes.* Any amount of state severance taxes paid at any first sale shall not be included in determining the price paid for purposes of paragraph (a).

(c) *Pipeline produced gas.* A first sale acquisition cost shall be imputed to gas produced by an interstate pipeline which is acquired by the interstate pipeline in a transaction which is treated as a first sale for purposes of Title I of the NGPA. The imputed first sale acquisition cost shall be the applicable maximum lawful price under Title I of the NGPA.

§ 282.304 Incremental pricing threshold.

(a) *General rule.* For purposes of this part, the incremental pricing threshold applicable for any month shall be:

(1) $1.48 per million Btu's in the case of March 1978; and

(2) in the case of any month thereafter, the amount, per million Btu's determined under this section for the preceding month multiplied by the monthly equivalent of the annual inflation adjustment factor (as defined in section 101 (a) of the NGPA) applicable for such month.

(b) *Publication.* Not later than 5 days before the beginning of each month, commencing with January 1980, the Commission shall issue the incremental pricing threshold applicable for such month. As soon as possible thereafter, such incremental pricing threshold shall be published in the Federal Register.

Subpart D—[Set forth in Final Rule Issued in Docket No. RM79-21]

Subpart E—Incremental Pricing Accounts and Surcharges

§ 282.501 General Rule.

(a) Each natural gas supplier shall, on a monthly basis, accumulate in an unrecovered incremental gas costs account, as provided in § 282.502, the costs described in paragraph (a) through (k) of § 282.301 as being subject to passthrough under this part.

(b) Each interstate pipeline shall derive a reduced PGA rate for each PGA period, as provided in § 282.503.

(c) Each month, in accordance with § 282.504, each natural gas supplier shall bill incremental pricing surcharges to the sale-for-resale customers and the non-exempt industrial boiler fuel facilities on the supplier's system.

(1) Surcharges shall be calculated to recover the lesser of the total incremental gas costs, as defined in § 282.504, which were incurred by the supplier during the prior month or an amount equivalent to the maximum surcharge absorption capability of the supplier's customers.

(2) The maximum surcharge absorption capability of a non-exempt industrial boiler fuel facility shall be the difference between the cost to the facility for its use of natural gas, calculated on the basis of the rates of its natural gas suppliers before inclusion of incremental pricing surcharges, and the cost of that same volume of natural gas priced at the alternative fuel price ceiling applicable to the facility. In the event that the rate of its natural gas supplier is in excess of the alternative fuel price ceiling applicable to the facility, the maximum surcharge absorption capability of the facility shall be deemed to be zero.

(3) The maximum surcharge absorption capability of a non-exempt industrial boiler fuel facility for any calendar month shall be determined on the basis of a meter reading made at the end of such month, *provided that* such meter reading may be made no earlier than 10 days prior to the last day of the month.

(d) Each month, in the case of interstate pipelines, the amount accumulated in the natural gas supplier's unrecovered incremental gas costs account which cannot be recovered by way of incremental pricing surcharges shall be transferred from that account to account 191, Unrecovered Purchased Gas Costs and recovered in accordance with § 282.505.

§ 282.502 Accounting

(a) *General rule.* For purposes of incremental pricing, each natural gas supplier shall establish an unrecovered incremental gas costs account, an unrecovered incremental surcharges account and an incremental gas cost adjustments account.

(b) *Establishment of accounts.* (1) *Unrecovered incremental gas costs account.* Each natural gas supplier shall establish an unrecovered incremental gas costs account. Such account shall be designated account 192.1, Unrecovered Incremental Gas Costs, for interstate pipelines following the Uniform System of Accounts, Parts 201 and 204 of this chapter. The underlying records of such account shall be maintained to permit identification of:

(i) the volumes and cost of each purchase that gave rise to costs being charged to the account;

(ii) the paragraph of § 282.301 under which the costs associated with such purchase qualify for inclusion in the account; and

(iii) any other charges to the account.

(2) *Unrecovered incremental surcharges account.* The unrecovered incremental surcharges account shall be designated account 192.2, Unrecovered Incremental Surcharges, for interstate pipelines following the Uniform System of Accounts, Parts 201 and 204 of this chapter. The underlying records of this account shall be maintained so as to permit identification of each incremental pricing surcharge debited to the account in accordance with paragraph (e).

(3) *Incremental gas cost adjustments account.* Each natural gas supplier shall establish an incremental gas cost adjustments account. Such account shall be designated account 805.2, Incremental Gas Cost Adjustments, for interstate pipelines following the Uniform System of Accounts, Part 201 of this chapter. Such account shall be designated account 731.2, Incremental Gas Cost Adjustments, for interstate pipelines following the Uniform System of Accounts, Part 204 of this chapter.

(c) *Debiting the unrecovered incremental gas costs account.* The unrecovered incremental gas costs account shall be debited and the incremental gas cost adjustments account shall be credited with:

(1) costs described in paragraphs (a) through (k) of § 282.301 which are incurred during each calendar month; and

(2) any other costs as permitted by order of the Commission.

(d) *Crediting the unrecovered incremental gas costs account.* (1) The unrecovered incremental gas costs account shall be credited and the incremental gas cost adjustments account shall be debited when costs included in the unrecovered incremental gas costs account are recovered by means of incremental pricing surcharges.

(2) The unrecovered incremental gas costs account shall be credited with any amount which was accumulated in the account for gas received during a calendar month but which, due to the alternative fuel price ceilings established pursuant to § 282.404, cannot be collected by way of incremental pricing surcharges to be billed during the subsequent month. Such amount may be transferred to account 191 immediately, but no later than the end of the month in which the applicable surcharges are billed.

(e) *Debiting the unrecovered incremental surcharges account.* A natural gas supplier's unrecovered incremental surcharges account shall be debited and the incremental gas cost adjustments account shall be credited with any incremental pricing surcharge which is billed to it by its supplier in accordance with a tariff sheet filed by such supplier in accordance with § 282.602.

(f) *Crediting the unrecovered incremental surcharges account.* The unrecovered incremental surcharges account shall be credited and the incremental gas cost adjustments account shall be debited for those amounts which are recovered by means of incremental pricing surcharges.

§ 282.503 PGA reduction.

(a) *General rule.* (1) An interstate pipeline company which files purchased gas adjustment (PGA) rate changes with the Commission under authority of § 154.38(d) shall, each PGA period, reduce its total projected gas acquisition cost by the amount which it projects it will recover during the next PGA period through incremental pricing surcharges. The total projected gas acquisition cost, as reduced, shall be used to derive the pipeline's PGA rate for the coming PGA period in the manner prescribed in the pipeline's effective PGA provision.

(2) The amount which an interstate pipeline projects it will recover through incremental pricing surcharges during a PGA period shall be the lesser of:

(i) the costs subject to incremental pricing, as described in paragraphs (a) through (l) of § 282.301, which the pipeline projects it will incur during the coming PGA period; or

(ii) the total of the projected maximum surcharge absorption capabilities (MSAC) of each of the non-exempt industrial boiler fuel facilities directly served by the pipeline, as computed in accordance with paragraph (b), plus the total of the projected MSAC's of the pipeline's sale-for-resale customers, as determined by each of the customers in accordance with paragraph (c) and reported to the pipeline in accordance with paragraph (d).

(b) *Projected MSAC of a non-exempt industrial boiler fuel facility.* (1) The projected MSAC of a non-exempt industrial boiler fuel facility for a coming PGA period shall be calculated by a natural gas supplier in accordance with the following formula, in which the symbol "^" indicates a projection:

$$\hat{M} = \frac{[(\hat{A}_1 - \hat{R}_1)\ \hat{V}_1]}{1 + \hat{T}_1} + \frac{[(\hat{A}_2 - \hat{R}_2)\ \hat{V}_2]}{1 + \hat{T}_2} + \ldots + \frac{[(\hat{A}_n - \hat{R}_n)\ \hat{V}_n]}{1 + \hat{T}_n}$$

where:

$\hat{M}$=Projected MSAC of the non-exempt industrial boiler fuel facility.

$\hat{A}$=Projected alternative fuel price ceiling for the non-exempt industrial boiler fuel facility, plus taxes, as determined in accordance with subparagraph (2).

$\hat{R}$=Projected rate per million Btu's (excluding any incremental pricing surcharge), plus taxes, at which the non-exempt industrial boiler fuel facility will purchase natural gas, as determined in accordance with subparagraph (3).

$\hat{V}$=Projected volume of natural gas (at 1,000 Btu's per cubic foot) that the non-exempt industrial boiler fuel facility will purchase from the natural gas supplier and use for boiler fuel, as estimated for each of the months "1" through "n" of the PGA period.

$\hat{T}$=Projected total percentage tax rate reflecting any state and local taxes applicable to an incremental pricing surcharge.

n=Last month of the PGA period.

(2)(i) As a value for "$\hat{A}$" for each of the months "1" through "n" of the coming PGA period, a natural gas supplier shall use the most recently established alternative fuel price ceiling applicable to the facility, plus taxes, unless the supplier elects to estimate the applicable alternative fuel price ceilings for each of the months of the PGA period. In that case, the estimated ceilings, plus taxes, may be used as values for "$\hat{A}$".

(ii) If a local distribution company desires assistance in estimating applicable alternative fuel price ceilings for each of the months of the coming PGA period, the interstate pipeline which supplies the local distribution company shall provide such assistance.

(3)(i) *Local distribution company.* As a value for "$\hat{R}$" for each of the months "1" through "n" of the coming PGA period, a local distribution company shall use its effective rate per million Btu's at the time of projection, plus taxes but exclusive of any incremental pricing surcharges, unless the local distribution company elects to adjust such rate to reflect general rate changes which it is known will occur during the PGA period under authority of a state or local regulatory body. If the local distribution company elects to adjust the rate, the values used for "$\hat{R}$" may reflect the adjustments for the months of the PGA period for which the adjustments are appropriate.

(ii) *Interstate pipeline.* As a value for "$\hat{R}$" for each of the months "1" through "n" of the coming PGA period, an interstate pipeline shall use its effective contract rate per million Btu's at the time of projection, plus taxes but exclusive of any incremental pricing surcharges, unless the pipeline elects to adjust such rate to reflect rate changes which it is known will occur during the PGA period.

(c) *Projected MSAC of a sale-for-resale customer.* With respect to each of its natural gas suppliers, the projected MSAC of a sale-for-resale customer shall be derived by adding the sum of the projected MSAC's of the non-exempt industrial boiler fuel facilities served directly by the sale-for-resale customer, as determined in accordance with paragraph (b), to the sum of the projected MSAC's of the customer's own sale-for-resale customers, as reported in accordance with paragraph (d), and multiplying the resulting total by the percentage reflecting the ratio between:

(i) the volume of natural gas (at 1,000 Btu's per cubic foot) which the customer estimates it will purchase from the supplier during the coming PGA period; and

(ii) the total of:

(A) the volume of natural gas (at 1,000 Btu's per cubic foot) which the customer estimates it will purchase from interstate pipelines;

(B) the volume of natural gas (at 1,000 Btu's per cubic foot) which is included in any of the categories specified in paragraphs (a) through (k) of § 282.301 and which the customer estimates it will purchase from sources other than interstate pipelines; and

(C) if the sale-for-resale customer is an interstate pipeline, the estimated volume of pipeline produced natural gas (at 1,000 Btu's per cubic foot) to which a first sale acquisition cost will be imputed under paragraph (c) of § 282.303.

(D) *Reporting.* (1) *Pipeline to request information.* Prior to the beginning of each of its PGA periods, each interstate pipeline shall request that each of its sale-for-resale customers report to it the customer's projected MSAC in a timely fashion.

(2) *Pipeline customers to report.* Each natural gas supplier shall respond to the requests of interstate pipelines for projected MSAC's for a coming PGA period in a timely fashion.

(e) *Scheduling by the Commission.* In those instances where the Commission finds that natural gas suppliers have not arranged for the reporting of information in accordance with this section, the Commission shall prescribe by order an appropriate schedule for the expeditious transmission of the information necessary for interstate pipelines to make their regular PGA filings with the Commission.

§ 282.504 Incremental pricing surcharge.

(a) *General rule.* Each natural gas supplier shall include an incremental pricing surcharge, stated as a dollar amount, in its monthly bills to the non-exempt industrial boiler fuel facilities and sale-for-resale customers on its system. Surcharges billed to non-exempt industrial boiler fuel facilities shall be determined in accordance with paragraph (c). Surcharges billed to sale-for-resale customers shall be determined in accordance with paragraph (d). Such surcharges shall recover, subject to the limitation of the alternative fuel price ceilings described in § 282.404, the total incremental gas costs as defined in paragraph (b), which were incurred by the natural gas supplier during the previous month.

(b) *Definitions.* For purposes of this section "total incremental gas costs" means the sum of the following:

(1) the amount of the costs accumulated in a natural gas supplier's unrecovered incremental gas cost account for a period; and

(2) any incremental pricing surcharges imposed on the natural gas supplier by its own supplier(s) for that period.

(c) *Surcharges on non-exempt industrial boiler fuel facilities.* (1) *General rule.* The incremental pricing surcharge to be billed for the previous month by a natural gas supplier for each of the non-exempt industrial boiler fuel facilities which it directly serves shall, subject to subparagraph (4), be the lesser of:

(i) the MSAC of the non-exempt industrial boiler fuel facility for the previous month, as determined in the manner described in subparagraph (2); or

(ii) the non-exempt industrial boiler fuel facility's pro rata share of the total incremental gas costs incurred by its natural gas supplier during the previous month, as determined in the manner described in subparagraph (3) of this paragraph.

(2) *MSAC of a non-exempt industrial boiler fuel facility.* (i) The MSAC of a non-exempt industrial boiler fuel facility for the previous month shall be determined in accordance with the following formula:

$$M = \frac{[(A-R)(V)]}{1+T}$$

where:
M=MSAC of the non-exempt industrial boiler fuel facility.
A=Alternative fuel price ceiling applicable to the non-exempt industrial boiler fuel facility for the previous month, plus taxes.
R=Rate per million Btu's (excluding any incremental pricing surcharge), plus taxes, at which the non-exempt industrial boiler fuel facility purchased gas from the natural gas supplier during the previous month.
V=Volume of natural gas (at 1,000 Btu's per cubic foot) supplied by the natural gas supplier to the non-exempt industrial boiler fuel facility for boiler fuel use during the previous month, as determined in accordance with clause (ii).
T=Total percentage tax rate reflecting any state and local taxes applicable to an incremental pricing surcharge.

(ii)(A) For the period January 1, 1980, through October 31, 1980, the volume of natural gas supplied to a non-exempt industrial boiler fuel facility for boiler fuel use during a month may be determined on the basis of:

(*1*) submetering determinations;

(*2*) estimates, as signed under oath by a responsible company official, that are furnished to the facility's natural gas supplier as required by the supplier for billing purposes; or

(*3*) a supplier-customer agreement, signed by responsible officials of the supplier and the customer.

(B)(*1*) Subject to clause (*2*), on and after November 1, 1980, the volume of natural gas supplied by a natural gas supplier to a non-exempt industrial boiler fuel facility for boiler fuel use during a month shall be deemed to be the total volume of natural gas supplied to the facility during the month, unless the natural gas supplier serving the facility distinguishes the volumes used for boiler fuel from the volumes not so used on the basis of submeter readings. If volumes used for boiler fuel are so identified, such volumes shall be used for purposes of determining the MSAC of the non-exempt industrial boiler fuel facility in accordance with clause (i).

(*2*) Certified monthly estimates or a supplier-customer agreement may be utilized to determine the volume of natural gas consumed in the facility for boiler fuel use for a period following November 1, 1980, *provided that* the owner or operator of the facility has obtained a purchase order for all submeters which will be needed in the facility by November 1, 1980, and such submeters will be installed within a reasonable period of time.

(3) *Pro rata share of total incremental gas costs.* A non-exempt industrial boiler fuel facility's pro rata share of the total incremental gas costs incurred by its natural gas supplier during the previous month shall be determined by multiplying the total incremental gas costs by a percentage reflecting the ratio between:

(i) the MSAC of the non-exempt industrial boiler fuel facility for the previous month, as determined in accordance with subparagraph (2); and

(ii) the sum of the MSAC's of the non-exempt industrial boiler fuel facilities on the natural gas supplier's system, as determined for the previous month in accordance with subparagraph (2), plus the sum of MSAC's reported to the natural gas supplier by its sale-for-resale customers for the previous month.

(4) *Optional billing procedures for local distribution companies.* A local distribution company may elect to bill non-exempt industrial boiler fuel facilities served by it at the level of the alternative fuel price ceilings plus taxes which are applicable to such facilities.

(i) If a local distribution company bills a non-exempt industrial boiler fuel facility at the level of the applicable alternative fuel price ceiling for service during the previous month and the MSAC of the non-exempt boiler fuel facility for such month exceeds the facility's pro rata share of the total incremental gas costs incurred by the local distribution company during the previous month, then such local distribution company shall refund the excess to the facility in the next bill rendered to the facility.

(d) *Surcharges on sale-for-resale customers.*

(1) *General rule.* The incremental pricing surcharge to be collected by a natural gas supplier from each of its sale-for-resale customers shall be the lesser of:

(i) the MSAC of the sale-for-resale customer for the previous month, as determined by the customer in the manner described in subparagraph (2) of this paragraph and reported to the natural gas supplier pursuant to paragraph (e); or

(ii) the sale-for-resale customer's pro rata share of the total incremental gas costs incurred by its natural gas supplier during the previous month, such share being determined in the manner described in subparagraph (3) of this paragraph.

(2) *MSAC of a sale-for-resale customer.* With respect to each of its natural gas suppliers, the MSAC of a sale-for-resale customer shall be derived by adding the sum of the MSAC's of the non-exempt industrial boiler fuel facilities served directly by the sale-for-resale customer, as determined for the

previous month in accordance with subparagraph (2) of paragraph (c), to the sum of the MSAC's of the customer's own sale-for-resale customers, as reported for the previous month in accordance with paragraph (e), and multiplying the resulting total by the percentage reflecting the ratio between:

(i) the volume of natural gas (at 1,000 Btu's per cubic foot) purchased by the customer from the natural gas supplier during the previous month; and

(ii) the total of:

(A) the volume of natural gas (at 1,000 Btu's per cubic foot) which the customer purchased from interstate pipelines during the previous month;

(B) the volume of natural gas (at 1,000 Btu's per cubic foot) which is included in any of the categories specified in paragraph (a) through (k) of § 282.301 and which the customer purchased from sources other than interstate pipelines during the previous month; and

(C) if the sale-for-resale customer is an interstate pipeline, the volume of pipeline produced natural gas (at 1,000 Btu's per cubic foot) to which a first sale acquisition cost has been imputed under paragraph (C) of § 282.303.

(3) *Pro rata share of total incremental gas costs.* A sale-for-resale customer's pro rata share of the total incremental gas costs incurred by its natural gas supplier during the previous month shall be determined by multiplying the total incremental gas costs incurred by the percentage reflecting the ratio between:

(i) the MSAC reported to the natural gas supplier by the sale-for-resale customer for the previous month in accordance with paragraph (e); and

(ii) the sum of the MSAC's of the non-exempt industrial boiler fuel facilities on the natural gas supplier's system, as determined for the previous month, in accordance with subparagraph (2) of paragraph (c), plus the sum of the MSAC's reported to the natural gas supplier by its sale-for-resale customers for the previous month in accordance with paragraph (e).

(4) *Optional billing procedures for interstate pipelines.* An interstate pipeline company may elect to bill any sale-for-resale customer it serves by utilizing the projected surcharge of the customer for the previous month, as filed under § 282.602(a)(1)(ii).

(i) If an interstate pipeline bills a sale-for-resale customer at the level of the projected surcharge for service during the previous month and the projected surcharge of the sale-for-resale customer for such month exceeds the actual surcharge that should have been billed for that month, as calculated in accordance with paragraph (d)(2), then the interstate pipeline shall refund the excess to the sale-for-resale customer in the next bill rendered to the customer.

(ii) If an interstate pipeline bills a sale-for-resale customer at the level of the projected surcharges for service during the previous month and the projected surcharge of the sale-for-resale customer for such month is less than the actual surcharge that should have been billed for that month, as calculated in accordance with paragraph (d)(2), then the interstate pipeline shall bill the difference to the sale-for-resale customer in the next bill rendered to the customer.

(e) *Reporting.* (1) *Pipeline to request information.* Each interstate pipeline shall request that, each month, each of its sale-for-resale customers report its MSAC to the pipeline in a timely fashion for the monthly billing of incremental pricing surcharges.

(2) *Pipeline customers to report.* Each month each natural gas supplier shall respond to the requests of interstate pipelines for its MSAC.

(3) *Suppliers to customers.* Each month each natural gas supplier shall inform each of its interstate pipeline sale-for-resale customers of the amount of the incremental pricing surcharge which will be billed to such customer. Such information shall be conveyed within sufficient time so as to enable the last customer in a chain of sale-for-resale interstate pipeline customers to bill incremental pricing surcharges to its customers in a timely fashion.

(f) *Scheduling by the Commission.* In those instances where the Commission finds that natural gas suppliers have not arranged for the reporting of information in accordance with this section, the Commission will prescribe by order an appropriate schedule for the transmission of the information necessary for the monthly billing of incremental pricing surcharges.

§ 282.505 Recovery of amounts in excess of maximum surcharge absorption capabilities.

In the case of interstate pipelines, the amount accumulated in the unrecovered incremental gas costs account for gas received during a month which, due to alternative fuel price ceilings, cannot be recovered through incremental pricing surcharges shall be collected under the Commission's provisions governing recovery of unrecovered gas costs as set forth in § 154.38(d)(4).

§ 282.506 Refunds.

The jurisdictional portion of any refund (including interest applicable thereto) which is attributable to service provided to non-exempt industrial boiler fuel facilities prior to January 1, 1980, which has not been flowed through to such users as of December 31, 1979, shall be flowed through as a lump sum payment in appropriate amounts to each appropriate natural gas supplier for the benefit of such users. Such refunds shall be calculated on the basis of sales to such users during the period when the rates which give rise to the refund were in effect.

Subpart F—Filing Requirements

§ 282.601 FERC gas tariff provisions.

(a) *Incremental pricing surcharge provision.* Each interstate pipeline shall establish an incremental pricing surcharge provision in its FERC Gas Tariff. The incremental pricing surcharge provision shall provide for the passthrough of costs in accordance with the requirements of this part.

(b) *Revised PGA provision.* Each interstate pipeline shall revise its PGA provision, as established in accord with § 154.38(d), to provide for a reduced PGA rate in accordance with the requirements of this part.

(c) *Filing dates.* The incremental pricing surcharge provision and revised PGA provision shall be filed with the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and served on all parties by November 1, 1979. The provisions shall become effective on December 1, 1979, unless disapproved in whole or in part by the Commission.

§ 282.602 Tariff sheets.

(a) *General rule.* (1) On or before December 1, 1979, for the period January 1, 1980, to the effective date of the pipeline's next normally scheduled PGA filing, each interstate pipeline shall file concurrently:

(i) a tariff sheet reflecting a reduced PGA rate as determined in accordance with § 282.503; and

(ii) a tariff sheet reflecting the projected incremental pricing surcharges for each month, as determined on the basis of data used in deriving the reduced PGA rates referenced in clause (i), for each of the direct sale non-exempt industrial boiler fuel facilities and the aggregate amount applicable to each sale-for-resale customer on the pipeline's system.

(2) Revisions to the tariff sheets filed pursuant to subparagraph (1) shall be filed in accordance with each interstate pipeline's normal PGA schedule, as necessary to revise the previously effective tariff sheets.

(b) *Form and filing requirements.* Any tariff sheet filed pursuant to paragraph (a) shall be subject to the provisions and requirements of Part 154 of this chapter.

(c) *Service.* The interstate pipeline which files tariff sheets pursuant to paragraph (a) shall concurrently serve copies on each customer subject to the tariff sheets and each interested state commission.

(d) *Material to be submitted.* (1) Tariff sheets filed pursuant to paragraph (a) shall be accompanied by a report containing computations showing the derivation of the reduced PGA rate and the incremental pricing surcharges set forth in such tariff sheets.

(2) Beginning with the first filing subsequent to the effective date of this part, tariff sheets filed pursuant to paragraph (a) shall be accompanied by a supplement to the statement of a pipeline's current cost of purchased gas as required by § 154.38(d).

(i) Such supplement shall identify, for the prior PGA period, each source of supply which is within a category identified in paragraphs (a) through (k) of § 282.201 by API well identification number, if available, contract date and FERC rate schedule number. Where multiple wells are metered through a common delivery point or where production from multiple wells is sold under a single contract, the supplement shall identify each well that produces gas which is subject to this part. Such supplement shall identify the price paid for gas from each well identified in accordance with this paragraph.

(ii) Such supplement shall show for account 192.1 for the prior PGA period:

(A) total monthly debits to such account;

(B) total monthly credits to such account resulting from the recovery of costs by means of incremental pricing surcharges; and

(C) the monthly amount credited to clear the account to account 191 and the date the clearing entry was made.

(iii) Such supplement shall show for account 192.2 for the prior PGA period:

(A) the incremental pricing surcharges debited to the account each month by the pipeline; and

(B) the total monthly credits to the account resulting from the recovery of costs by means of incremental pricing surcharges.

(f) *Additional information.* The Commission may, upon receipt of a tariff sheet filed pursuant to this section, require the submission of additional information as it deems necessary and appropriate.

§ 282.603 Informational filings.

(a) *General rule.* For informational purposes, each month commencing with March 1980, each interstate pipeline company shall file with the Commission a statement setting forth the incremental pricing surcharge actually billed to each non-exempt industrial boiler fuel facility and sale-for-resale customer on its system in the preceeding month.

(b) *Address.* The informational filings required by paragraph (a) shall be addressed to Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

[FR Doc. 79-30758 Filed 10-3-79; 8:45 am]

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18 CFR Part 282

[Docket No. RM79-21; Order No. 50]

Regulations Implementing Alternative Fuel Price Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTIONS: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations which set ceilings on the prices which can be charged to large industrial facilities under the incremental pricing program mandated by Title II of the Natural Gas Policy Act of 1978, for their use of natural gas as a boiler fuel. These regulations will result in large industrial users paying a price for their natural gas equivalent to the price they would pay for the fuel oil which they could burn as an alternative to natural gas.

EFFECTIVE DATE: December 1, 1979.

FOR FURTHER INFORMATION CONTACT:

Norman A. Pedersen, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8377.

Nancy E. Williams, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8033.

James C. Liles, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8158.

Regulations Implementing Alternative Fuel Price Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978.

Issued September 28, 1979.

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I. Background

Title II of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95-621) requires that interstate pipelines and local distribution companies pass through certain portions of their natural gas acquisition costs to industrial users in the form of incremental pricing surcharges. Section 204 of the NGPA provides, however, that such surcharges may not cause the rates for natural gas charged to an incrementally priced industrial facility to exceed the appropriate alternative fuel cost of the facility. The regulations promulgated in this order provide for the determination of this ceiling on incremental pricing.

This "Final Rule" is a companion to the "Rule Exempting Industrial Boiler Fuel Facilities from Incremental Pricing Above the Price of No. 6 Fuel Oil" issued today in this docket and transmitted to Congress for its review pursuant to subsection 206(d) of the NGPA.[1] If Congress permits that exemption rule to become effective on

[1] *Regulations Implementing the Alternative Fuel Price Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978*, "Rule Exempting Industrial Boiler Fuel Facilities from Incremental Pricing Above the Price of No. 6 Fuel Oil", Docket No. RM79-21, issued September 28, 1979.

December 1, 1979 as proposed, it will hold in abeyance until November 1, 1980 so much of the regulations prescribed herein as are inconsistent with having the ceiling on incremental pricing set at the price of No. 6 high sulfur fuel oil. After November 1, 1980, the "three-tier approach" to incremental pricing ceilings as adopted in this order would become effective.

Either House of Congress, however, may adopt a resolution disapproving the exemption rule at any time during the first 30 days of continuous session of Congress after a copy of the rule has been submitted to each House of Congress. If either House adopts such a resolution of disapproval, the "three-tier approach" as embodied in the regulations prescribed in this order shall become fully effective on December 1, 1979, no portion being held in abeyance.

This final rule is also a companion to the general incremental pricing rule issued today in Docket No. RM79-14.[2] That rule establishes a mechanism for incremental pricing in accordance with section 201 of the NGPA, and it establishes procedures for obtaining exemptions under section 206 of the NGPA.

The NGPA specifies that the incremental pricing program shall be implemented in two phases. The only facilities covered during the first phase, as required by section 201 of the NGPA, will be industrial facilities using large amounts of natural gas as boiler fuel. Title II requires that the regulations implementing this first phase be promulgated by November 9, 1979. The regulations adopted in this order apply to facilities affected by this first phase of incremental pricing.

During Phase II of the program, as provided by section 202 of the NGPA, incremental pricing may be extended to a broader class of industrial users than those affected by the first stage. The regulations implementing the second phase must be promulgated by May 9, 1980 and will be subject to Congressional review. Congress, by a veto by either House, may reject the Phase II rule proposed by the Commission.

II. Public Input to This Proposed Rulemaking

There has been extensive public participation at all stages of this rulemaking proceeding. Prior to the promulgation of the May 11, 1979 Notice of Proposed Rulemaking (44 FR 29090, May 18, 1979), the Commission's staff held a series of informal public conferences with state officials, representatives from the natural gas industry, natural gas end-users and other interested parties.

The first informal public conference regarding incremental pricing was convened on February 12, 1979 in Docket No. RM79-14. Notice of this conference was issued on January 12, 1979 (44 FR 6133, January 31, 1979). Though the primary subject of that conference was the incremental pricing mechanism, a number of participants expressed views about the alternative fuel price ceiling on incremental pricing.

On April 2, 1979, a public conference was called in this Docket, RM79-21, specifically to give interested parties an opportunity to discuss the issue of the ceiling. In the March 14, 1979 Notice convening the conference (44 FR 16937, March 20, 1979), participants were asked to discuss eight issues regarding establishment of the ceiling:

1. Should the alternative fuel cost ceiling be based on the cost of No. 2 fuel oil, the cost of No. 6 fuel oil or something in between?
2. What should be the regions for which alternative fuel cost ceiling should be determined?
3. Should the ceiling be based on the wholesale price of fuel oil or the retail price?
4. Should the alternative fuel cost ceiling be based on the price quoted for fuel oil before state and local taxes are included, or should the ceiling be based on the price after state and local taxes are included?
5. What should be the length of the period for which weighted averages should be taken in deriving alternative fuel cost ceiling from oil price data?
6. Should there be a downward adjustment of the average cost of oil? If so, what should be the factor by which there will be a downward adjustment?
7. How often should data on fuel oil prices be collected?
8. How frequently should the ceiling be published?

Many written and oral comments were received from parties with various viewpoints. Also, on April 12, 1979, the Commission staff met with members of the National Association of Regulatory Utility Commissioners to obtain data, views and comments regarding the ceiling from the perspective of state regulators.

After the issuance of the Notice of Proposed Rulemaking on May 11, 1979, hearings were convened in St. Paul, Los Angeles, Atlanta and Washington, D.C. Representatives of state agencies, the natural gas industry, end-users, and consumer groups appeared to present data, views, and arguments. Additionally, more than 50 written comments were submitted.

Lastly, the Energy Information Administration (EIA) distributed a consultation worksheet to selected potential respondents to Form EIA-194, the form which EIA will use to collect data to be used in generating alternative fuel price ceilings for each incremental pricing region. The consultation worksheets solicited the respondents' comments on a working draft of the form. Those worksheets are hereby made part of the public record in this proceeding.

III. The Ceiling Level: No. 2, No. 6 or Three-Tier?

The principal issue is whether the ceiling on incremental pricing should be set at the price of No. 2 (distillate) fuel oil, or whether statutorily specified conditions are met so that the Commission may exercise its statutory discretion to reduce the ceiling to some level not lower than the price of No. 6 (residual) fuel oil.

Congress intended Title II of the NGPA to provide a benefit to residential and commercial customers by directing first to industrial users the increase in natural gas acquisition costs which result from the NGPA. Those costs would otherwise, under conventional ratemaking principles, be borne by all customers—residential, commercial, and industrial—on an average volumetric or "rolled-in" basis.

Congress recognized, however, that for natural gas pipeline and distribution systems, industrial load provides a vital benefit to residential and commercial ("high priority") customers. The industrial customers bear capital costs which, if they left the system, would have to be borne entirely by the high priority customers.

If there were no ceiling on incremental pricing and, as a result, incremental pricing were permitted to take the price of gas above the cost of fuel oil, industries would find it to their benefit to switch from gas to oil. The result, of course, would be that capital costs which theretofore had been borne by industry would be shifted to residential and commercial customers. This would result in an increase rather than a decrease in the rates charged to the very customers that Title II was intended to benefit. To prevent such an anomalous result, section 204 of the NGPA provides that incremental pricing surcharges may not cause the rates charged for natural gas to an incrementally priced industrial facility to rise above the price of the

[2] *Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978*, "Final Rule", Docket No. RM79-14, issued September 28, 1979.

"appropriate alternative fuel cost" of the facility.

It remains to be determined, however, what the "appropriate alternative fuel cost" of an incrementally priced facility might be. Subsection 204(e) provides that the "appropriate alternative fuel cost" shall be the price paid for No. 2 fuel oil in the region in which the facility is located, but the Commission is authorized to reduce the ceiling to a point not lower than the level of No. 6 fuel oil. Subsection 204(e) states:

Sec. 204 Method of Passthrough

* * * * *

(e) Determination of Alternative Fuel Cost.—

(1) In General.—Except as provided in paragraph (2), the appropriate alternative fuel cost for any region (as designated by the Commission) shall be the price, per million Btu's, for Number 2 fuel oil determined by the Commission to be paid in such region by industrial users of such fuel.

(2) Reduction of Appropriate Alternative Fuel Cost Allowed.—The Commission may, by rule or order, reduce the appropriate alternative fuel cost—

(A) for any category of incrementally priced industrial facilities, subject to the rule required under section 201 (including any amendment under section 202 to such rule) located within any region and served by the same interstate pipeline; or

(B) for any specific incrementally priced industrial facility which is subject to such requirements and which is located in any region;

to an amount not lower than the price, per million Btu's, for Number 6 fuel oil determined by the Commission to be paid in such region by industrial users of such fuel, if and to the extent the Commission determines, after an opportunity for written and oral presentation of views, data, and arguments, that such reduction is necessary to prevent increases in the rates and charges to residential, small commercial, and other high-priority users of natural gas which would result from a reallocation of costs caused by the conversion of such industrial facility or facilities from natural gas to other fuels, which conversion is likely to occur if the level of the appropriate alternative fuel cost were not so reduced.

The Commission interprets this subsection to indicate Congressional intent that the alternative fuel price ceiling should be kept at the level of No. 2 fuel oil unless it is likely that a No. 2 ceiling will result in fuel switching and a shifting of capital costs that would increase residential and commercial rates. If it is likely that a No. 2 ceiling would cause fuel switching and an increase in residential and commercial rates over what they would be if there were a lower ceiling, the Commission believes that Congress intended that the ceiling should be reduced to prevent such a likelihood. The Conference Report supports this interpretation:[3]

The conferees urge the Commission to take whatever action it deems appropriate or necessary * * * to avoid any delays in reducing the substitute fuel level so as to avoid the likelihood of conversions from natural gas by industrial users if those conversions would result in increases in natural gas rates for any residential, small commercial, and other high priority customers. The conferees intend that in determining the likelihood of these conversions occurring, the Commission move rapidly in the administrative hearings so as to avoid the irreparable damage which the conferees believe will occur to high priority users if these other industrial users, faced with uncertain natural gas rates, begin taking steps to secure alternate fuel supplies.

The substantial dependence of the United States on imported oil adds special urgency to this Congressional admonition. If incremental pricing were permitted to induce increased industrial use of fuel oil, United States' dependence on imported oil would be exacerbated, contrary to the national interest.

However, while the Commission believes it is authorized to reduce the ceiling so as to minimize the likelihood of fuel switching and its adverse consequences, the Commission also believes that subsection 204(e) implies that Congress did not intend that the ceiling be reduced to the price of No. 6 fuel oil if such a ceiling would be likely to result in residential and commercial rates being higher than they would be with a No. 2 ceiling.

In view of the intent underlying subsection 204(e), in its May 11, 1979 Notice of Proposed Rulemaking the Commission considered the likely impact that a uniform No. 2 or No. 6 ceiling would have on residential and commercial rates. Additionally, the Commission endeavored to devise a system of multiple ceilings under which the ceiling applicable to any particular incrementally priced facility would be high enough to maximize the recovery of incremental costs from that facility, yet would be low enough to minimize the likelihood that the facility would switch to an alternative fuel. Such a scheme would seem to offer the potential to achieve the maximum possible flow-through of incremental costs to industrial boiler fuel customers without causing load loss.

Accordingly, the Commission proposed that three alternative fuel price ceilings be established for each region of the country. One ceiling would be set at the level of No. 2 fuel oil, another at the level of low sulfur No. 6 fuel oil and a third at the level of high sulfur No. 6 fuel oil. Each industrial boiler fuel facility would be incrementally priced only up to the level of the lowest priced fuel oil that it could in fact use. This approach would seem to avoid the establishment of a blanket ceiling for all users which might be too high for some, resulting in their loss to the system, while at the same time being too low for others, allowing them to escape some of the costs which Congress intended they should bear under the incremental pricing program.

On the basis of the data, views and arguments furnished during the extensive proceedings in this docket the Commission must decide whether, under subsection 204(e), the ceiling on incremental pricing should be reduced from the No. 2 level. If so, the Commission must determine whether the ceiling should be set at the price of No. 6 oil or whether the proposed three-tier method should be adopted.

A. Should there be a single-tier ceiling set at the price of No. 2 fuel oil?

The record in this proceeding shows that there are a large number of industrial boiler fuel facilities which have the capability to burn fuel oils which are cheaper than No. 2. Furthermore, the record shows that those facilities are price sensitive and would shift to oil if the price of gas charged to them were permitted to rise to the level of No. 2 fuel oil. Thus, setting the ceiling at the No. 2 level would seem lilely to have the results that Congress instructed the Commission to deter.

1. *Many industrial boiler fuel facilities are capable of burning fuel oil which is cheaper than No. 2 fuel oil.*—In connection with the conferences held before the issuance of the Notice of Proposed Rulemaking, a number of participants submitted data showing that, to a substantial extent, fuel oils other than No. 2 are the alternative fuels for industrial boiler fuel facilities that will be subject to incremental pricing. For example, the State of Louisiana commented that, in Louisiana, large industrial boilers equipped to burn No. 6 fuel oil outnumber by more than 3 to 1 boilers that are equipped to burn No. 2 fuel oil. Similarly, the Public Staff of the North Carolina Utilities Commission submitted an analysis of the industrial service currently provided by the Public Service Company, one of three gas utility companies serving North Carolina. This study showed that of industrial boiler fuel users served by that utility, 87.75 percent, based on volumetric use, have a capability to use No. 5 or No. 6 fuel oil.

[3] S. Rep. No. 95-1752, 95th Cong., 2nd Sess. 100 (1978).

In response to the Notice of Proposed Rulemaking, many commenters submitted similar data. For example, the South Carolina Public Service Commission surveyed the natural gas distributors subject to its jurisdiction. It found that, for sales of gas by subsidiaries of Carolina Energies, Inc., to facilities which may be subject to incremental pricing, 64 percent of the sales are to customers that use No. 6 high sulfur fuel oil as their alternative to natural gas. For South Carolina Electric and Gas Company, 84 percent of the sales are to industrial facilities which have a high sulfur No. 6 capability. The figure is 60 percent for United Gas Company and 100 percent for Peoples Natural Gas Company of South Carolina.[4]

Various distributors have testified to the same effect about the amount of industrial load on their systems which has the capability to use No. 6 as an alternative to gas. For example, of the gas sold by Consumers Power Company that may be subject to incremental pricing, 91 percent is sold to facilities with the capability to use No. 6 fuel oil.[5] The figure is 50 percent for Northern Natural Gas Company.[6] The Public Service Electric and Gas Company commented that 88 percent of the volumes it sold to industrial boiler fuel facilities were sold to facilities which could use No. 4 or No. 6 fuel oil.[7]

The various comments of state agencies, distributors, pipelines and industrial end-users about how a large number of industrial boiler fuel facilities have the capability to use No. 6 fuel oil as an alternative to gas agree with data made available to the Commission by the Energy Information Administration. These data were described in the Notice of Proposed Rulemaking in this docket.[8]

They show that a substantial number of industrial boiler fuel facilities have the capability to use No. 6 fuel oil as an alternative to natural gas.

As for why some facilities have the capability to use the less expensive No. 6 fuel oil while some do not, commenters explained that No. 6 fuel oil is usually more difficult to use than No. 2. Due to its high viscosity, No. 6 fuel oil will not flow readily at normal or low temperatures without being heated. In order to use No. 6 fuel oil rather than No. 2, an industrial facility needs to have special equipment such as heaters in its fuel tanks and steam tracers on the pipes carrying the oil from the storage tanks to the burner tip.

For a small facility or a facility which needs oil only on an infrequent basis as a backup for gas in case of curtailment, it is often uneconomic to incur the capital cost of installing the capability to burn No. 6 fuel oil. And, even if it is economic, it simply may not be worth the effort of installing the equipment needed to burn No. 6 fuel oil.

As commenters pointed out, however, large industrial facilities or facilities which are curtailed more frequently are in a far different position. Due to their greater fuel requirements, these facilities have in many cases opted to incur the relatively modest capital costs of installing heaters and steam tracers so as to take advantage of the substantial ($1.00 or more per MMBtu) price differential between No. 2 and No. 6 fuel oil. Thus, for example, the record shows that at the 3-M Company, which operates over 100 facilities and plants in 28 states, both No. 2 and No. 6 fuel oil are used as alternative fuels. When asked at the St. Paul hearing why 3-M uses more expensive No. 2 fuel oil, the 3-M representative responded:

> Basically because of the size of the installation. They are relatively small facilities and small plants with a relatively low usage requirement.

Similarly, the representative of Georgia Kraft Company testified at the Atlanta hearing:

> The basic fuels for industrial energy as I know it as representative of a large manufacturer is No. 6 fuel oil—high sulphur No. 6 fuel oil.

In sum, the record in this proceeding demonstrates that there are a substantial number of industrial plants that have the capability to burn No. 6 fuel oil or that could easily and reasonably acquire such a capability. In general, use of No. 2 fuel oil is preferred only by small facilities or by facilities where gas use is so seldom interrupted that it is not worth the expense or bother to use No. 6 fuel oil.

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[4] The following data were submitted by the South Carolina Public Service Commission:

The provisions of the NGPA and the proposed regulations in Docket No. RM79-21 will potentially affect twenty-four (24) industrial customers of the jurisdictional subsidiaries of Carolina Energies, Inc. Those subsidiaries are Carolina Pipeline Company, Inc., and Carolina Natural Gas Corporation. In accordance with approved curtailment plans and based on current supplies of natural gas, those customers are entitled to a total of 60,929 Mcfd. Eighteen (18) of those customers use No. 6 (high sulfur) fuel oil as their alternate fuel. They account for sixty-four percent (64%) of the daily entitlement.

Seventeen (17) industrial customers of South Carolina Electric and Gas Company may be affected by the provisions of the NGPA and the proposed regulations. Those customers are entitled to a total volume of 21,593 Mcfd. Nine (9) of those customers utilize No. 6 (high sulfur) fuel oil as an alternate fuel, and those customers account for eighty-four percent (84%) of the daily entitlement.

Two (2) industrial customers of United Cities Gas Company may be affected by the NGPA and the proposed regulations. The total entitlement of those customers is 2,529 Mcfd. One of those customers uses sixty percent (60%) of the total entitlement and utilies No. 6 (high sulfur) fuel oil as its alternate fuel.

Three (3) industrial customers of Peoples Natural Gas Company of South Carolina may be affected by the provisions of the NGPA and the proposed regulations. Those customers are entitled to 3,337 Mcfd. Since their alternate fuel is No. 6 (high sulfur) fuel oil, the total entitlement would be affected by the NGPA and the proposed regulations.

[5] Consumers Power estimated that 22.3 Bcf of gas sold on its system will be subject to incremental pricing. This gas is sold to 47 industrial boiler fuel customers, thirty of which have the capability to burn No. 6 fuel oil. Those 30 customers, however, purchase 20.2 (91%) of the 22.3 Bcf of gas which will be subject to incremental pricing.

[6] Northern Natural Gas Company, in comments filed prior to the Notice of Proposed Rulemaking, said there are approximately 60 customers on its system which will be subject to the first phase of the incremental pricing program. Northern Natural estimated that these customers will, in 1980, use approximately 3.5% of the volume of natural gas sold by Northern. Northern found through discussions with its customers that for approximately one-half of the gas volumes consumed by the large industrial users, No. 6 fuel oil is the alternative fuel. Thus, Northern anticipates that there would be a substantial loss of industrial sales if the alternative fuel price ceiling remained at the No. 2 level.

[7] Public Service Electric and Gas Company commented that it had 27 industrial boiler fuel customers which consumed 32,241 Mcf per day. Of that, 28,241 (88%) was consumed by the 20 customers which had the capability to burn No. 4 or No. 6 fuel oil:

Lowest Price Alternate Fuel	No. of Customers	Mcf Per Day
#2	7	4,000
#4	6	3,991
#6	14	24,250

[8] In its May 11, 1979 Notice of Proposed Rulemaking, the Commission stated at page 13 (mimeo ed.) (44 FR 29090, 29093 [May 18, 1979]):

In addition to the comments, the Commission has available to it data obtained by the Energy Information Administration (EIA). In December 1978, the Energy Information Administration of DOE sent a questionnaire, Form EIA-134, to interstate pipelines, local distribution companies, state commissions and other interested persons to gather information, on a voluntary basis, about the alternative fuel capabilities of both large and small industrial boilers. EIA also solicited opinions as to what the ceiling should be. The Commission has examined the results of this survey, bearing in mind that the responses were voluntary and thus do not constitute a statistically valid sample. The survey indicated that a significant number of boiler fuel facilities in a majority of the states are equipped to burn No. 6 fuel oil. Further, the majority of respondents favored a ceiling based on the No. 6 oil price. However, the survey also indicated that there are a number of boiler fuel facilities which will be subject to the first phase of the incremental pricing program that only have an alternative fuel capability to use No. 2 fuel oil.

The Commission has also analyzed the data reported on the EIA-50 form. EIA-50 is used to gather information on the alternative fuels that are used to offset curtailments in the delivery of natural gas. Analysis indicates that during the period April 1977-March 1978, large industrial users utilized No. 5 or No. 6 fuel oil to offset approximately 40 percent of the natural gas curtailment they experienced. This percentage translates to approximately 64 million barrels of oil. The EIA-50 data also indicate that No. 1 or No. 2 fuel oil was utilized to offset approximately 20 percent of natural gas curtailments during the same period.

2. *Industrial boiler fuel facilities are price-sensitive.* The record establishes, further, that industrial facilities that have residual fuel oil burning capability are price sensitive and will switch to fuel oil if gas is priced at the No. 2 level. For example, the representative of the Process Gas Consumer Group (PGC), the members of which own and operate over 1,000 plants in virtually every state, said that non-exempt industrial facilities "generally have the capability to switch on or off gas extremely rapidly." If incremental pricing pushes "gas prices above the price of the cheapest potential alternate fuel, such users will not hesitate to switch off of gas."

PGC's view was shared by each of the other sixteen industries or industrial groups which responded to the Notice of Proposed Rulemaking. Kennecott Copper Corporation's Chino Mine Division, located in southwestern New Mexico, commented that non-exempt end users "have the ability to switch almost instantaneously to cheaper alternate fuels." The Hoerner Waldorf division of Champion International Corporation in St. Paul, Minnesota, testified:

> Since [Hoerner Waldorf's St. Paul] facility has the capability of using both natural gas and No. 6 fuel oil, it can switch to the lower cost of these fuels on very short notice. [A] difference of only one cent per million Btu would be sufficient incentive for one facility to switch to the lower cost fuel.

Similarly, the representative of George Kraft Company of Georgia and Alabama testified:

> My company can switch completely on or off natural gas in about 30 minutes' time, and we do it rather frequently. When gas prices approach oil prices on an equivalent Btu basis, we're going to shop among the alternatives that we have; and we're going to make that decision, as I said, on almost a daily basis.

The representative of 3-M Company testified that 3-M already has facilities "where we have already discontinued using natural gas because its price exceeds the cost of our alternate fuel."

The Commission concludes that not only does a large amount of incrementally priced industrial boiler fuel load have the capability to burn No. 6 fuel oil, but there is a strong likelihood that this load would shift from gas to oil if gas were priced at the level of No. 2 fuel oil.

3. *What would be the impact of a uniform No. 2 ceiling on high-priority customers?* As for the precise, total amount of incrementally priced load that would be lost if there were a uniform No. 2 ceiling, commenters disagree. The American Gas Association (AGA) surveyed its members and found that 40 percent more load loss would occur with a No. 2 ceiling than with a No. 6 ceiling. The Department of Energy, on the other hand, surveyed five distribution companies and found there would be a 50 to 80 percent load loss for those companies, if there were a No. 2 ceiling.

Based on the data in the record, then, the precise amount of load loss which would occur if there were a No. 2 ceiling cannot be established. Further, as the data submitted by the South Carolina Public Service Commission and others show, the amount of load loss would vary from distributor to distributor, depending on how much industrial boiler fuel load had No. 6 burning capability.

Commenters generally agreed, however, that the load loss which would result from a No. 2 ceiling would be substantial and would be disadvantageous to residential and commercial customers. The Commission notes, especially, that the National Association of Regulatory Utility Commissioners as well as the state regulatory commissions of California, Michigan, Ohio, North Carolina, South Carolina and Wisconsin strongly argued against a uniform No. 2 level on this ground. The comment of Chairman Daniel J. Demlow of the Michigan Public Service Commission was representative:

> Our initial concern was that the target price based on the cost of the No. 2 fuel oil would result in the loss of considerable volumes of gas sales to non-exempt boiler fuel facilities. We affirm this concern here. Several boiler fuel customers of gas utilities in Michigan have already converted from gas to residual fuel oil because current firm industrial gas rates are approximately equal to the cost of residual fuel oil. This loss of load has already resulted in significantly increased costs to residential and other high priority gas customers in Michigan.

Several other state and local authorities who provided comments in response to the Notice of Proposed Rulemaking supported the view that the extent of load shifting that would be induced by a No. 2 ceiling would disadvantage the high-priority consumers they represent. Among these were the Mayor of St. Paul, Minnesota; the Director of Minnesota Office of Consumer Services and the representative of the Georgia Consumers' Utilities Council. They echoed the view of the state regulatory commissions that the Commission must lower the ceiling from the No. 2 level in order to protect residential and commercial customers.

The Federal Energy Regulatory Commission gives great weight to the expert judgment of the state and local officials who testified or contributed comments. They are familiar with local industrial fuel usage patterns, and they are in a position to be acutely aware of the likely consequences of industrial load loss on residential and commercial consumers. Moreover, they have special responsibilities with respect to the interests of these groups.

The Commission concludes that a No. 2 ceiling on incremental pricing would be likely to cause substantial load switching, and the loss of such load would be likely to result in a shifting of capital costs to the disadvantage of high-priority customers.

The question remains, however, as to whether these customers would be better off with an incremental pricing ceiling set at the price of No. 6 fuel oil rather than at the price of No. 2 fuel oil.

B. Should the ceiling be reduced to the level of No. 6 fuel oil?

In view of the substantial load loss that might occur with a ceiling based on the price of No. 2 oil, the American Gas Association (AGA) as well as other commenters urged that there be a uniform incremental pricing ceiling set at the level of No. 6 fuel oil.

AGA supported its argument for a uniform No. 6 ceiling by submitting a study purporting to show that, on a national average basis, residential and commercial rates would be lower with a uniform No. 6 ceiling than with a No. 2 ceiling. AGA surveyed 41 of its member companies to determine the industrial load loss they would incur if there were a uniform No. 2 ceiling on incremental pricing. Based on the results of that survey, AGA concluded that if the alternative fuel price ceiling were established at the No. 2 rather than No. 6 level, 741 to 788 billion cubic feet (Bcf) of industrial boiler fuel sales would be lost in 1980.[9] This represents 39 percent to 41 percent of the total 1,900 Bcf of industrial boiler fuel sales that AGA projects for 1980.

AGA then attempted to estimate the effect of the loss of approximately 800 Bcf of industrial sales on residential gas rates. AGA projected 1981 residential rates under two simplified scenarios. Under the "Low Cap Scenario", it was assumed that industrial boiler fuel facilities would be incrementally priced at the estimated 1981 price of low sulfur (0.3%) No. 6 fuel oil, $3.50 per MMBtu. Further, it was assumed that no load

[9] The 741 Bcf figure represents the load loss which AGA says would result from a No. 2 ceiling if ceiling price levels were determined for small incremental pricing regions such as SMSA's. The 788 Bcf figure represents what the load loss would be under a No. 2 ceiling if large regions such as states were used.

loss would be caused by incremental pricing. Under the "High Cap Scenario", it was assumed that industrial boiler fuel facilities would be subject to incremental pricing at the projected level of the price of No. 2 fuel oil in 1981, $4.10 per MMBtu, and that 800 Bcf of industrial sales would be lost.

AGA concluded that rates to residential and commercial customers would be higher under the High Cap Scenario than under the Low Cap Scenario. Under the High Cap Scenario, the national average charge for providing gas to residential and other high-priority customers in 1981 would be $3.21 per MMBtu, 12 cents more than the $3.09 per MMBtu that AGA estimated would be charged under the Low Cap Scenario.

According to the AGA study, the higher charge would be attributable to three factors. First, an additional 5 cents per MMBtu would have to be charged under the High Cap Scenario to recover fixed transmission and distribution costs since there would be fewer sales from which to recover those costs. Second, additional seasonal and peak shaving costs would raise rates by 2 cents per MMBtu. Third, the total amount of incremental costs that could be absorbed by industrial customers would actually be $495 million less under the High Cap Scenario, resulting in a 5 cents per MMBtu increase in high-priority customer rates.[10]

AGA concluded that the Commission should establish a uniform ceiling on incremental pricing at the level of "the lowest cost appropriate alternative fuel."

[10] In order to determine the total amount of incremental costs which would be absorbed by industrial customers under the two scenarios, AGA assumed that the average price of gas charged to industrial users would be $2.35/MMBtu before the addition of any incremental pricing surcharges. AGA assumed that No. 2 fuel oil would sell for $4.10/MMBtu in 1981. Thus, the average maximum surcharge absorption capability of incrementally priced customers under a No. 2 "High Cap" ceiling would be $1.75/MMBtu. AGA further assumed that low sulfur (0.3%) No. 6 fuel oil would sell for $3.50/MMBtu, and that under a low sulfur No. 6 "Low Cap" ceiling all incrementally priced industrial facilities would be surcharged to the full extent of their surcharge absorption capability. By multiplying the amount of gas to be incrementally priced under each scenario by the amount of the surcharge, AGA determined that, even though the low sulfur No. 6 "Low Cap" ceiling was 60 cents less than the No. 2 "High Cap" ceiling, the increase in volumes available to be surcharged under a low sulfur No. 6 ceiling resulted in there being a total "Low Cap" surcharge recovery of $2.07 billion, $495 million more than the $1.575 billion AGA estimated would be recovered if there were a No. 2 ceiling. The $495 million difference would be spread over all other customers, with the result that gas prices to high-priority customers would be 5 cents/MMBtu higher under the High Cap Scenario than under the Low Cap Scenario.

The Department of Energy, however, submitted a more complex study using a more sophisticated methodology that raises substantial doubts about the AGA conclusion that a ceiling set at the No. 6 level would generally benefit high-priority consumers.

In transmitting the study, Secretary of Energy James R. Schlesinger expressed the Department's view, that it is in the national interest for natural gas be used to displace more costly imported oil. Thus, the Secretary stated, the Department would prefer to have the ceiling on incremental pricing set at the level of high sulfur No. 6 fuel oil.

Secretary Schlesinger went on to say, however, that, in the Department's view, if adoption of a uniform No. 6 ceiling decreased the surcharge absorption capability of incrementally priced facilities so much that, in at least some cases, the reduction would offset the benefit to high-priority customers of avoiding load loss, then, under subsection 204(e) of the NGPA, the ceiling should not be reduced to a uniform No. 6 level. In other words, the test for whether the ceiling should be reduced to the price of No. 6 fuel oil is "whether the total revenue over and above the cost of natural gas paid by fewer incrementally-priced users at a distillate price would be greater than the total revenue over and above the cost of natural gas paid by more incrementally priced users at a lower price."

The Department of Energy's study suggests that it is problematical as to whether a No. 6 ceiling would benefit high-priority customers more than a No. 2 ceiling. Thus, although the Department of Energy would have preferred a uniform No. 6 ceiling on the basis of public policy considerations, Secretary Schlesinger supported the Commission's proposed three-tier approach as a reasonable way to conform to the mandate of Title II of the NGPA.

DOE studied the effect that industrial boiler fuel load losses of 40 percent, 50 percent, 66.7 percent and 80 percent would have on the high-priority customers of 38 distribution companies. DOE first analyzed the effect such load losses would have, based on May, 1979 oil prices.[11] DOE found that in May residential and commercial customers would have been better off with a ceiling set at the No. 2 rather than No. 6 level. This held true regardless of whether load loss were assumed to be at the low extreme of 40 percent or at the high extreme of 80 percent.

[11] For purposes of its study, DOE used $3.80 per MMBtu as the price for No. 2 fuel oil in May, 1979. For high sulfur No. 6 fuel oil, DOE averaged prices for No. 6 oils with sulfur contents of 1.0% and above to derive an average price of $2.60 per MMBtu.

DOE found, further, that the effect of load loss was dependent on the level of oil prices. June prices were projected by DOE to be substantially higher than May's. While May, 1979 prices reflected world crude oil prices of $15.00 per barrel, DOE projected that June, 1979 prices would reflect world prices of $19.60 per barrel.[12] As a result, since the cost of gas would be relatively unchanged, the amount that could be collected from industrial customers at a high sulfur No. 6 ceiling would be significantly greater in June than in May. Accordingly, while in May high-priority customers would have been better off with a No. 2 ceiling even if there had been load loss of 80 percent, in June such customers would be better off with a No. 2 ceiling only if load loss stayed below a point in the range of 50 percent to 66.7 percent.

In either case, however, the results of the DOE study contrast strikingly with AGA's contention that high priority customers would be *worse* off with a No. 2 ceiling even with load loss as low as 40 percent. Several important differences between the AGA and DOE studies explain the divergent results.

One difference was that different grades of No. 6 fuel oil were used in the two studies. The price of No. 6 fuel oil varies significantly on the basis of sulfur content, with high sulfur No. 6 fuel oil being less expensive than low sulfur No. 6 oil.[13] Thus, high sulfur No. 6 oil is preferred by industrial users, and a No. 6 ceiling has to be set at the price of high sulfur No. 6 fuel oil if it is to be assumed that no load loss will occur. Accordingly, DOE used an average price for high sulfur (1.0 percent and above) No. 6 fuel oil in estimating the amount industrial boiler fuel facilities could be charged if they were billed at a No. 6 ceiling. AGA, however, used a projected price of the more expensive low sulfur (0.3 percent) No. 6 fuel oil in deriving its "low cap" ceiling. The effect of using a low sulfur No. 6 oil price was that AGA overstated the contribution that incrementally priced industries would make to high-priority customers if there were a "Low Cap" ceiling.

A second difference between the DOE and AGA studies was that AGA measured the 1981 contribution per MMBtu of industrial customers to high-

[12] DOE projected the June, 1979 price of No. 2 fuel oil to be $4.20 per MMBtu. The average price of No. 6 high sulfur fuel oil was projected to be $3.40 per MMBtu.

[13] Indeed, the price differential between high sulfur No. 6 fuel oil and low sulfur No. 6 oil can be as great as that between No. 2 fuel oil and low sulfur No. 6 oil. Generally, low sulfur No. 6 fuel oil is used only in facilities which are not permitted to burn high sulfur No. 6 fuel oil due to air quality standards.

priority customers by subtracting the projected average retail industrial rate ($2.35 MMBtu) from the alternative fuel price ceilings.[14] DOE's study points out, however, that what an industrial customer contributes to recovery of system costs and thus, to the high-priority customers is the amount the industrial customer is charged in excess of the actual marginal cost of the gas acquired to serve him.

Stated differently, the cost of supplying an additional MMBtu of gas to an industrial customer is equal to the highest wellhead price paid by the supplying interstate pipeline plus variable conditioning and transportation costs and taxes. If an industrial customer leaves the system, the highest priced gas which otherwise would be purchased to serve the industrial customer would not be purchased. As a result, the average "rolled-in" cost of gas would be reduced to the benefit of the remaining customers. DOE's methodology captured this benefit which would be gained by the high-priority customer if there were industrial load loss.[15] AGA's method did not.[16]

Lastly, DOE did not concur with AGA that load loss resulting from a No. 2 ceiling would result in additional storage costs. Industrial customres are not storage facilities. Having them as customers permits a lessening of capital charges per unit by permitting a higher load factor during off-peak periods. Consequently, if they were lost from a system, capital charges to high-priority customers would be higher. But no less gas would be available to those high priority customers during peak periods. Thus, the loss of industrial customers would not, in itself, give rise to a need for additional storage facilities.

More importantly than these methodological differences, however, DOE's study illustrates the inherent and quantitatively unresolvable uncertainty about whether lowering the ceiling from the price of No. 2 fuel oil to the level of No. 6 oil would benefit residential and commerical customers. As has been discussed above, there is uncertainty about the amount of load loss which would occur if there were a No. 2 ceiling. DOE's study shows that there is a second—and even more serious—concern. While something between 50 percent and 66 percent load loss would have justified a No. 6 ceiling in June, 1979, only one month earlier not even an 80 percent load loss would have justified a No. 6 ceiling.

Thus, while it may be possible to determine whether a No. 6 ceiling is justified on the basis of data for one month, the ceiling might not be justified for another month. As DOE's figures for May and June, 1979, illustrate, changes in world oil prices can transform either a No. 6 or No. 2 ceiling from a benefit to a detriment to high-priority customers. There is high and inherent uncertainty about the future course of world oil prices as well as inherent but less uncertainty about the future price of gas, and such uncertainty obviates the possibility of determining whether, in the future, high-priority customers would be benefitted by a No. 6 rather than a No. 2 ceiling on incremental pricing.

C. The Three-Tier Approach

With the three-tier approach proposed in the May 11, 1979 Notice of Proposed Rulemaking, the Commission sought to steer, as the Notice put it, between the Scylla and Charybdis of No. 2 and No. 6 ceiling levels.

As commenters pointed out, subsection 204(e) of the NGPA does not require that the Commission devise and adopt a scheme that would minimize residential and commercial rates. It only requires that for the Commission to reduce the ceiling on incremental pricing from the price of No. 2 fuel oil, it must be likely that such a reduction would result in lower residential and commercial rates than would an unreduced No. 2 ceiling. Yet, the three-tier approach not only satisfies that statutory requirement, it also maximizes the benefits of incremental pricing for high-priority customers.

To demonstrate this, DOE submitted the stylized demand curves set forth in Figures 1 and 2. As Figure 1 shows, if there is a "single-tier" ceiling set at the price of No. 2 fuel oil, there will be an increase in the contribution to system costs per unit of incrementally priced gas. Due to load loss, however, less gas will be subject to incremental pricing. On the other hand, a No. 6 ceiling will decrease the per unit contribution but will increase the volume of gas subject to incremental pricing. Thus, using DOE's Figure 1, the ceiling should be lowered from the price of No. 2 fuel oil to the price of No. 6 oil if area R is larger than area D. As just discussed, however, not only is there insufficient information to determine which area is larger at a given point in time, but the size of the areas will change over time.

These problems inherent in trying to determine the relative sizes of areas D and R are avoided under the three-tier approach, as shown in DOE's Figure 2. The advantage of the three-tier ceiling is that by keeping the No. 6 fuel oil customers on the system, it avoids load loss without reducing the contributions from the distillate customers: area T in Figure 2 is always greater than area D because D is included in T. Similarly, area T is always greater than areas L or H, illustrating that a three-tier ceiling will always provide greater benefits to residential and commercial customers than either a low sulfur No. 6 ceiling as used in AGA's study or a high sulfur No. 6 ceiling as used in DOE's study.

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[14] AGA projected that the price of No. 2 fuel oil would be $4.10 in 1981 and that the price of No. 6 would be $3.50. Thus, each industrial customer would contribute $1.75/MMBtu if there were a No. 2 ceiling and $1.15/MMBtu if there were a No. 6 ceiling.

[15] In its study, DOE assumed that the cost of providing gas to industrial customers is the cost incurred during off-peak summer periods (the acquisition cost plus variable transportation and processing costs and taxes). When gas is supplied during the winter, the marginal cost of gas may increase significantly, especially if the additional gas is delivered from underground storage, liquified natural gas storage, synthetic natural gas plants, or other peak-shaving facilities. Thus, even DOE's study, insofar as it reflected the off-peak marginal cost of gas and not the peak marginal cost, understated the benefit to high priority customers of shedding industrial load during peak periods.

[16] To illustrate, for 1981, the year used in the AGA study, DOE would subtract $2.69 (a wellhead price of $2.34 plus allowances for processing, transportation and gross receipts tax), not AGA's average retail industrial rate of $2.35, from the projected No. 2 and No. 6 ceiling prices in order to derive the per MMBtu contribution of industrial customers to system costs. The effect would be to reduce the per MMBtu contribution that would be made by industrials. Thus, under DOE's approach, more load loss would have to result from a No. 2 ceiling to warrant using a No. 6 rather than No. 2 ceiling.

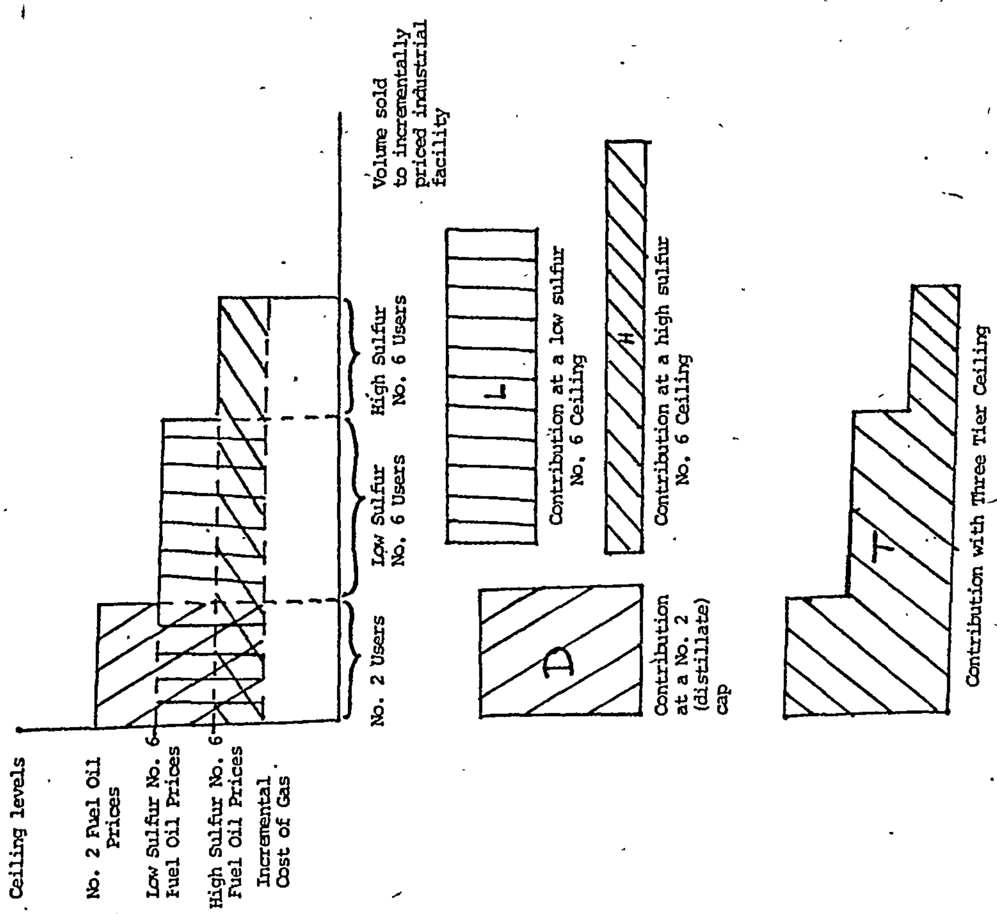

FIGURE 2

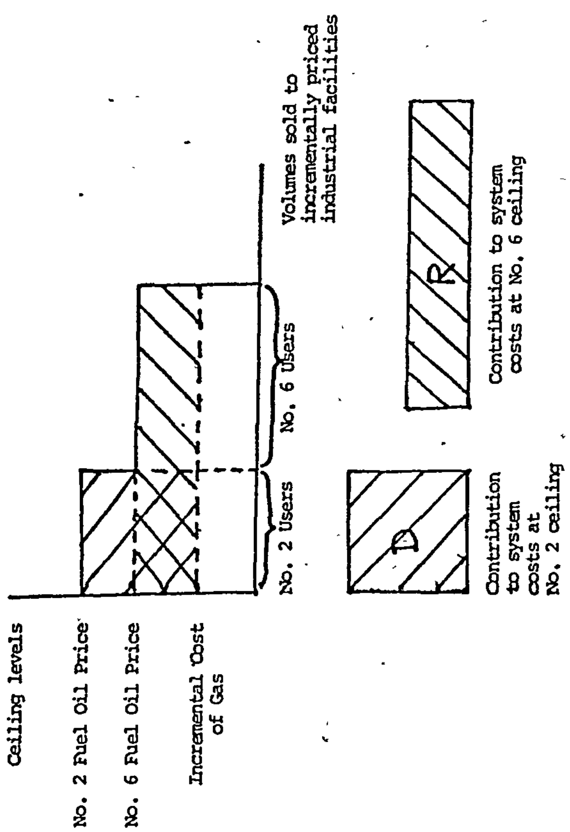

FIGURE 1

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DOE went on to examine a sample pipeline. DOE found that, for that pipeline system, incremental pricing would result in a 19 cents/Mcf reduction in average residential rates if there were a No. 2 ceiling. If there were a No. 6 ceiling the reduction would be 23 cents/Mcf. If there were a three-tier ceiling, however, the reduction in residential rates would be 28 cents/Mcf.[17]

Although few other commenters analyzed the problems as eloquently as DOE, there was widespread support for the conclusion that follows from DOE's model. The simplicity of the analysis required to show that the three-tier ceiling satisfies the statutory standard of subsection 204(e) of the NGPA contrasts with the complexity of attempting to predict and quantify the effects of a No. 2 or No. 6 ceiling. DOE's stylized demand curves show simply and convincingly that a three-tier ceiling will always result in lower residential and commercial rates than would either a No. 2 or No. 6 ceiling.

A three-tier ceiling is also consistent with Secretary Schlesinger's statement that the nation's domestic gas resources should be used to displace imported oil. In the DOE study tendered in support of Secretary Schlesinger's comment in this proceeding, DOE observed that the use of gas to displace imported oil creates three types of benefits: downward pressure on world oil prices, reduction in the chance and cost of interruption, and reduction in the balance of payments deficit. DOE estimates suggest that the value or "premium" on reducing imports is about $3.00 per barrel, or about 50 cents per Mcf, above the world oil price.

As mentioned above, AGA estimated in its comments that if there were a No. 2 fuel oil ceiling on incremental pricing, industrial users of approximately 800 Bcf per year would switch from No. 2 to No. 6 fuel oil. This would result in a U.S. demand for imports of about 400,000 barrels per day. Thus, based on the $3.00 per barrel "premium" on imported oil, the loss to the nation from an increase in imported oil due to there being a No. 2 ceiling would be over $400 million per year, assuming that the cost of gas supplied to industrial customers was the same as the cost of No. 6 fuel oil.

The actual loss to the nation would be even greater, however. The marginal cost of supplying gas off peak to industrial users is lower than the price of products made from imported oil. The marginal cost of additional gas from conventional domestic sources supplied to most industrial consumers is little more than the wellhead price of the gas, an amount still well below the cost of high sulfur No. 6 fuel oil. If the difference between the marginal cost of additional gas supplies and the price of high sulfur No. 6 fuel oil is assumed to be 75 cents per Mcf,[18] the total loss to the nation of burning oil rather than gas would be $1 billion, $400 million being attributable to the $3.00 per barrel "premium" on imported oil with $600 million being attributable to the difference between the price of high sulfur No. 6 fuel oil and the marginal cost of gas from conventional domestic sources. This loss would be avoided under the three-tier approach, however, since that appoach will avoid the industrial load loss that would attend a single-tier ceiling set at the price of No. 2 fuel oil.

D. Arguments Against the Three-Tier Approach

Various arguments were advanced in favor of adoption of a single-tier No. 6 ceiling rather than the three-tier approach. The principal argument was that if the three-tier approach were adopted, industries that are not now equipped to burn No. 6 fuel oil would be motivated to install such equipment solely to qualify for a low incremental pricing ceiling. A uniform No. 6 ceiling, it was argued, would avoid such allegedly uneconomic installation of otherwise unneeded equipment.

It was further argued that a three-tier ceiling would be discriminatory against smaller plant operators who could not afford to install No. 6 capability. Such an industrial consumer would be billed incremental pricing surcharges at a No. 2 level although his larger and wealthier competitors could afford to install No. 6 capability so as to avail themselves of the lower No. 6 ceiling.

Additionally, it was argued that a single-tier No.6 ceiling would pose less of an administrative and enforcement burden than would a three-tier ceiling, and that a No. 6 ceiling would be environmentally beneficial.

In the companion order issued today in this Docket, the Commission has expressed its concern that the three-tier approach may induce significant investment in No. 6 oil burning capability solely to gain the advantage of a lower incremental pricing ceiling. The amount of this induced investment cannot be estimated with precision, but the record indicates that it could be a sizable amount. Thus, the Commission is extremely concerned about letting the three-tier approach go into effect without further time to gain familiarity with the incremental pricing program, the industrial facilities which will be incrementally priced, and the extent to which the three-tier approach would be likely to result in an inducement to install otherwise unneeded No. 6 oil burning equipment.

Accordingly, in the companion order the Commission provides for an exemption under subsection 206(d) of the NGPA to hold the upper two tiers of the three-tier system in abeyance for 10 months from January through October, 1980, to provide a period in which a better understanding of the implications of the three-tier approach can be obtained.

The Commission is also concerned about the administrative and enforcement burden which will be occasioned by the three-tier approach. As noted by the Commission in the companion order, a further benefit of the 10 month exemption is that having a single-tier ceiling during at least the first few months of incremental pricing will ease implementation of an effective program. Perhaps most importantly, the likelihood of there being erroneous ceiling prices which cause load loss would be minimized.

As for the environmental argument for a single-tier No. 6 ceiling, the Commission's Environmental Assessment indicates that a three-tier rather than No. 6 ceiling would not have any adverse environmental impact. However, the Commission observes in the companion order that the 10 month exemption would provide an opportunity to evaluate further the environmental implications of the three-tier approach with the benefit of having the incremental pricing program actually in place.

One commentator argued that there should be a single ceiling at the No. 2 fuel oil level rather than a three-tier ceiling. The National Consumer Law Center, Inc., (NCLC) urged that the Commission avoid the load loss which would result from a No. 2 ceiling by taking steps to insure the availability of gas to industrial users in return for them being incrementally priced at a level higher than their alternative fuel capability. NCLC, however, did not explain how the Commission is to overcome the apparent jurisdictional

[17] DOE observed that these results suggest that the biggest effect on residential and commercial rates comes from having incremental pricing in place, and that the differences in rates resulting from using different ceilings are relatively small compared to the rate reduction which will result just from having incremental pricing.

[18] In its study DOE used $2.51 as the marginal cost of gas for May and June, 1979. The price of high sulfur No. 6 fuel oil, based on a projected June, 1979 world oil price of $19.60, was $3.40, a difference of 89 cents from the marginal cost of gas. (The May, 1979 price of high sulfur No. 6 fuel oil, however, was $2.60, resulting in a nine cents difference. This, again, illustrates the impact a change in world oil prices can have.)

barriers to it exercising curtailment authority over retail sales of distribution companies subject to state or local regulation. Nor did NCLC present any information on how much load loss could be avoided by assuring supply to incrementally priced end-users, assuming the Commission had authority to achieve such an end.

The Commission concludes that the three-tier approach as proposed in the Notice of Proposed Rulemaking best satisfies the Congressional intent underlying subsection 204(e) of the NGPA. Accordingly, that approach is adopted in this final rule. However, due to the concerns discussed above and discussed in greater detail in the companion order issued today in this docket, the Commission, in that companion order, finds that it would be appropriately cautious and in the public interest to hold the upper two tiers in abeyance for 10 months until November 1, 1980.

IV. Other Issues Regarding the Ceilings on Incremental Pricing

Given that a three-tier ceiling is superior to having a single-tier ceiling either at the No. 2 or No. 6 level, a question arises about whether there should be more than three tiers. Particularly, should there be additional tiers for blends of No. 2 and No. 6 fuel oil and for the different No. 6 fuel oils, the cost of which varies according to sulfur content. Additionally, there is a question about how to handle alternative fuels other than oil.

A. Blends

No. 4 and No. 5 fuel oil are usually obtained by blending No. 2 and No. 6 oil. Thus, they are generally cheaper than No. 2 oil, but more expensive than No. 6. In the Notice of Proposed Rulemaking, it was proposed that facilities which had the capability to use No. 4 or No. 5 fuel oil would be incrementally priced at the No. 2 level.

Parties objected, saying, most frequently with reference to No. 5 fuel oil, that if facilities which had the capability to burn a blended fuel oil were incrementally priced at the level of No. 2 fuel oil, the price of gas would be pushed above the price of their alternative fuel, and they would leave the gas system.

Several solutions were urged upon the Commission. One was to add two tiers, one reflecting the price of No. 4 fuel oil and one reflecting the price of No. 5, to the proposed three-tier approach. In response, the Commission notes that there is enough of an administrative and enforcement burden with a three-tier approach without stretching the limits of administrative feasibility yet further with a five-tier ceiling. Further, it is apparent to the Commission that EIA will have difficulty enough implementing the three-tier approach without having to generate five ceiling prices for each incremental pricing region of the country.

Another suggestion was to use a "weighted average" of the prices of No. 2 and No. 6 fuel oil to derive the ceiling prices for No. 4 and No. 5 fuel oil. There is, however, no evidence in the record suggesting any systematic correlation between the prices of No. 2 and No. 6 fuel oil on the one hand and the prices of No. 4 and No. 5 on the other. Further, there is no evidence of the ratio of No. 2 to No. 6 fuel oil which is used—if one is consistently used—in blending to get No. 4 or No. 5 oil.

A third suggested approach was to let the low sulfur No. 6 ceiling apply to a facility which has the capability to burn blended fuel oil. The Commission shall adopt this solution with regard to No. 5 oil. No. 5 is only slightly more expensive than low sulfur No. 6 fuel oil. Thus, relatively little surcharge absorption capability is lost if facilities capable of using No. 5 fuel oil are priced at the low sulfur No. 6 level. And more importantly, No. 5 oil shares many of the characteristics of No. 6 fuel oil: it has a high viscosity which requires special equipment for it to be burned.

No. 4 oil, however, does not resemble No. 6 oil in its characteristics. Indeed, due to its lower viscosity, in many instances it can be burned in facilities equipped to burn No. 2 fuel oil. Thus, if end-users were permitted to have a No. 6 ceiling apply to them on the basis that they were capable of burning No. 4 fuel oil, there would be a danger that a No. 6 ceiling could be claimed by end-users whose alternative fuel was actually No. 2 fuel oil. Accordingly, this final rule will not permit the user of No. 4 oil to avail himself of a No. 6 ceiling. However, the Commission notes that such a user may seek an adjustment as provided in subsection 502(c) of the NGPA and section 1.41, of the Commission's regulations.

B. Sulfur Levels

Several parties commented that since the price of No. 6 fuel oil varies with sulfur content, each level of sulfur content should be treated as a separate alternative fuel with its own ceiling level. Accordingly, the Associated Gas Distributors (AGD) proposed that separate ceilings be established for No. 6 fuel oils with sulfur contents of 0.3 percent, 0.5 percent, 1.0 percent and 1.5 percent and above. CF&I Steel Corporation (CF&I), on the other hand, stated, "No. 6 fuel oil is normally marketed at at least three different gradations of sulfur content—0.3 percent sulfur content, 1.0 percent sulfur content and 2.2 percent sulfur content." Accordingly, CF&I urged that ceilings be set for each of those three grades of No. 6 fuel oil.

There is, however, a limit to the number of levels for which data can be collected and ceilings published on a monthly basis. As stated above, it is going to be difficult enough for that task to be performed with only three ceiling levels, without compounding the difficulty by trying to add ceiling levels.

A related concern has to do with establishing the breaking point between high and low sulfur No. 6 fuel oil. In the Notice of Proposed Rulemaking "low sulfur" fuel oil was defined as oil containing one percent or less sulfur. Conversely, "high sulfur fuel oil" was defined as being oil containing more than one percent sulfur. The Michigan Commission recommended that high sulfur oil be defined as including one percent or more sulfur with low sulfur No. 6 being defined as including less than one percent sulfur. The Commission believes, however, that the definitions in the Notice of Proposed Rulemaking would more closely comport with common practice in the oil industry.

United Distribution Company (UDC) urged the Commission to adopt a yet lower breaking point of .75 percent sulfur. This, however, would go too far toward permitting a "high sulfur" ceiling for facilities which actually may only use what is commonly accepted as being low sulfur fuel.

C. Alternative Fuels Other Than Oil

Air Products and Chemicals, Inc., (Air Products) and the Chemical Manufacturers Association (CMA) said that some firms utilize alternative fuels other than oil (e.g., waste products, ethane, or refinery off-gas). Further, these fuels are priced at parity with the price of No. 6 fuel oil, since that is the fuel with which they compete. Yet, the facilities using the parity-priced alternative fuels frequently cannot burn No. 6 fuel oil and would, under the proposed regulations, be incrementally priced at the No. 2 fuel oil level. Accordingly, Air Products and CMA asked that a facility be incrementally priced at a No. 6 level if it certifies that it has available for purchase and is technically and legally permitted to burn an alternative fuel which is priced at parity with high or low sulfur No. 6 fuel oil.

Further, Potlatch Corporation urged that facilities which use alternative fuels such as coal, wood or spent pulping liquor be permitted to have incremental pricing ceilings set at the price of the alternative fuel or the price of No. 6 fuel oil, whichever is higher, regardless of whether or not there is parity pricing.

The Commission is not authorized under subsection 204(e) to base the appropriate alternative fuel cost for a facility on the costs of a fuel other than oil. Thus, ceiling levels shall not be established so as to recognize alternative fuels other than oil.

V. Regions

In the Notice of Proposed Rulemaking, the Commission proposed to establish incremental pricing ceilings for 39 separate regions. There would be eight large, multistate regions and 31 metropolitan regions. The eight large multistate regions were derived by modifying various regional divisions used by the Bureau of the Census, the Department of Energy and others to take into account energy production, distribution and sale patterns.

The 31 metropolitan areas reflected either Standard Metropolitan Statistical Areas (SMSA's) or Consolidated Metropolitan Statistical Areas (CMSA's) of one million or more in population, as determined by the Bureau of the Census of the United States Department of Commerce. Like SMSA's and CMSA's, the metropolitan regions observe county boundaries.

Alaska and Hawaii were not included in any of the regions, since neither state will be affected by the incremental pricing program. Neither presently utilizes gas from nor produces gas for the interstate market.

The metropolitan/multistate region approach would permit the establishment of incremental pricing ceilings which, to a substantial degree, would reflect market conditions in discrete marketing areas. There would be a relatively small dispersion of observed prices around the mean for each region, and sample size would probably be adequate. The nation's larger industrial and oil marketing concentrations are recognized, and state or county boundaries are followed.

NARUC and other commenters expressed the view, however, that the multistate regions are too large. As an example, NARUC cited the Southeastern region which extends from Virginia to Mississippi. NARUC observed that oil prices in the southeast vary between Atlantic and Gulf ports. Further, differences in transportation costs give rise to substantial oil price differences between inland and coastal areas.

Other commenters shared NARUC's concern. Alabama Gas Corporation said that Alabama and Mississippi are affected by Gulf coast prices which, at the time Alabama Gas filed its comments, had been averaging $2.00 per barrel less than Atlantic coast prices. South Carolina Electric and Gas Company (SCE&G), on the other hand, was particularly concerned about the difference in No. 6 oil prices between coastal and piedmont areas in the southeast.

The root of the concern expressed by NARUC, Alabama Gas, SCE&G and others seems to be that if incremental pricing ceilings are based on data for a region as large as the Southeastern multistate region, the ceilings may be low enough to forestall fuel switching, for example, on the Atlantic coast, but not on the Gulf coast. Similarly, the ceilings might prevent fuel switching in, for example, the piedmont area of Region 34, but there may be coastal areas of the Southeastern region where oil transportation costs are so low that oil will sell for less than gas priced at the incremental pricing ceiling.

This could well occur if ceiling prices were to be nothing more than weighted average oil prices. However, in the Notice of Proposed Rulemaking the Commission proposed that in deriving a ceiling price, weighted average oil prices would be adjusted downward to the higher of either the lowest observed price or a point two standard deviations removed from the mean. This would reduce the ceiling so much that it would be rare for an oil price to be lower than the ceiling. Nevertheless, the Commission notes the concern voiced by commenters about the size of the multistate regions.

A further concern that was mentioned by a number of commenters was that some distribution service areas would be divided between two or more regions. SCE&G's service area, for example, would be divided among three: New York (Region 3), Hartford (Region 2) and the New England multistate region. East Ohio Gas Company's (East Ohio) service area would be split between Cleveland (Region 13) and the Midwestern multistate region.

These and other commenters argued that having different industrial rates in the same service area would impose an administrative burden on distributors. Additionally, it would create price differentials between industrial facilities even though the facilities secure fuel supplies in the same market. Thus, East Ohio pointed out, price differentials could be created between competitors producing the same products in, for example, Akron and Canton, though they are less than 20 miles apart. Lastly, having different ceilings for the same service area would be contrary to traditional ratemaking principles. There would be different ceiling prices for industrial customers in Akron and Canton although the costs of serving them, and the alternative fuels available to them, are the same.

A variety of alternative proposals were made for modifying the proposed regions. NARUC, the Wisconsin Public Service Commission and several others urged that ceilings be determined for states. This, it was argued, would ameliorate the apprehension caused by having large multistate regions such as the Southeastern region. In any event, as the Wisconsin Public Service Commission pointed out, use of states as regions would prevent the ceiling prices in one state from being affected by the oil price conditions in other states. Lastly, Wisconsin observed, "There is much to be gained in terms of policy coordination and control by basing regions on political boundaries."

Other commenters, focusing particularly on the southeast, proposed that different ceilings be determined for coastal and piedmont areas even within the same state.

A number of parties who were particularly concerned about the "split service area" problem proposed that ceilings be determined for each service area. As an alternative, East Ohio proposed that if more than half of a distribution company's industrial sales volumes occur in only one of the incremental pricing regions among which the service area is divided, then the company should be permitted to use the ceilings as established for that region throughout the company's service area. United Distribution Companies (UDC) and Natural Gas Pipeline Company of America supported similar proposals.

Lastly, several parties urged that ceilings be determined for more than the 31 largest metropolitan regions. AGA urged that the original 31 metropolitan regions be supplemented to include the 60 metropolitan areas which have the highest rates of energy consumption. Others suggested particular additions to the list of metropolitan regions. For example, UDC asked that Syracuse and Rochester, New York; Charleston, West Virginia; Dayton and Toledo, Ohio; Springfield, Illinois and Kalamazoo, Michigan be added.

Upon considering these suggestions, the Commission will add states to the list of regions for which ceilings shall be published. This, combined with the fact that weighted average prices will be adjusted downward in deriving published ceilings, will eliminate the problems feared by commenters from the southeast. Further, in response to NARUC, the Wisconsin Commission and others, the use of states as regions will result in a more adequate recognition of state boundaries.

However, the multistate regions will not be discarded entirely. There may be states with such a low level of industrial oil usage that a statistically valid sample of industrial oil prices cannot be obtained. If such instances arise, the ceilings which will be published for the state shall be derived from data for the multistate region in which the state is located. Accordingly, while the multistate regions will not be incremental pricing regions for which ceilings shall be published, they will continue to have a function and will be described for informational purposes in the final regulations.

As for adding more metropolitan regions to the present list of 31, the Commission will not expand the list at this time. While it appears that it will not pose as substantial an additional burden on EIA to generate ceiling prices for the states as was originally anticipated, it does appear that it would be burdensome, especially at the outset of the incremental pricing program, to add to what EIA already finds to be a troublesome list of metropolitan regions.

EIA currently anticipates that it will be significantly more difficult to develop ceilings for the metropolitan regions than for states. Accordingly, while the Commission urges EIA to develop ceiling prices for both the contiguous 48 states and the 31 metropolitan regions on December 20, 1979 for use in January, 1980, the final regulations will require only that ceilings be published for the 48 contiguous states as of December 20. However, the ceilings must be published for all 79 regions—48 states and 31 metropolitan regions—no later than October 20, 1980. This will allow EIA up to 10 additional months to perfect its system for developing ceiling prices for the metropolitan regions. Until ceilings are available for metropolitan regions, the ceilings published for states shall be used without regard to the 31 metropolitan regions.

Lastly, the Commission is concerned about the split service area problem. The Commission will adopt a variant of the solution proposed by East Ohio. If a distribution company provides service in a geographically unified service area which is divided among two or more incremental pricing regions, and more than half of the company's incrementally priced industrial sales occur in only one of the regions, the company may so certify and use the ceiling for that region for its entire service area. If a company has a split service area problem but does not have at least 50 percent of its sales in any one of the incremental pricing regions among which its service area is divided, the company may file a petition to nominate which regional ceilings shall apply for its entire service area.

VI. Certification of Alternative Fuel Capability

In the Notice of Proposed Rulemaking, the Commission proposed that there would be a certification procedure for determining the alternative fuel capability of industrial boiler fuel facilities. If a facility were technically able and legally permitted to burn low sulfur No. 6 fuel oil, or if a facility were technically able and legally permitted to burn high sulfur No. 6 fuel oil, a responsible official of the facility could so certify. If there were such a certification, the facility would be incrementally priced at the level of the lowest priced alternative fuel—No. 6 low sulfur fuel oil or No. 6 high sulfur fuel oil—which the facility had been certified as being capable of burning. If there were no such certification of legal and technical capability to burn either low or high sulfur No. 6 fuel oil, a non-exempt facility would be deemed to have the capability to burn No. 2 fuel oil and would be incrementally priced at that level.

Certifications would be made through the filing of an alternative fuel capability affidavit, signed under oath by a responsible company official, with the Commission.[19] A copy of the executed affidavit would be filed with the natural gas supplier serving the facility. Blank affidavits would be supplied to industrial customers by their suppliers prior to the January 1, 1980 commencement of the incremental pricing program, and they would be available on an ongoing basis after that for the benefit of firms which subsequently install No. 6 alternative fuel capability. The certification would only have to be filed once in order for a facility to qualify for a No. 6 ceiling price.

The proposed regulations required that owners retain any documents showing that a facility is equipped with No. 6 oil burning capability for a period of three years following the date a certification of alternative fuel capability is filed with the Commission. The type of proof which would fulfill this requirement, aside from the No. 6 oil burning equipment itself, would be, for example, bills for the actual installation of the equipment, a qualified engineer's report that No. 6 capability is in place or bills for purchases of No. 6 fuel oil. This retention of records would allow for the audit of filed certifications by Commission enforcement personnel. An affiant would be required to describe on his alternative fuel capability affidavit what he will retain as evidence for his claim that his facility is capable of burning a No. 6 oil.

The proposed rules required a natural gas supplier to have available for public inspection all alternative fuel capability affidavits he received. Additionally, all such affidavits filed with the Commission would be available to the public. Any interested person who desired to protest any certification of alternative fuel capability would be permitted to do so by filing a protest in accordance with section 1.10 of the Commission's Rules of Practice and Procedure.

Any industrial user which believes that the self-certification procedure imposes a special hardship on him would be permitted to request administrative relief under the adjustment procedures promulgated under subsection 502(c) of the NGPA.

In general, these certification procedures were supported by commenters. Several criticized various aspects of the procedures, however. Their comments and criticisms are considered below.

A. The Test for Alternative Fuel Capability

The proposed test for being able to certify to a No. 6 high or low sulfur oil burning capability was that the affiant's facility be "technically capable and legally permitted" to burn No. 6 high or low sulfur fuel oil, as the case may be. A number of parties objected that if the Commission insisted that there be an actual, installed capability to burn a No 6 fuel oil, many facilities which could not burn No. 6 fuel oil would be induced to install the necessary equipment just in order to qualify for one of the No. 6 ceilings on incremental pricing, even though installing such equipment would be otherwise uneconomic and inefficient.

As a solution to this "induced installation" problem, several commenters proposed that the Commission abandon the three-tier approach and establish, instead, a single-tier No. 6 high sulfur ceiling. Others, however, suggested that the Commission solve the problem not by abandoning the three-tier approach but, instead, by abandoning the requirement that No. 6 oil burning equipment

[19] A copy of the alternative fuel capability affidavit, as revised to reflect the final regulations adopted in this order, is appended hereto as Appendix A.

actually be installed for a facility to qualify for a No. 6 ceiling. Thus, they urged that the Commission permit companies to certify that they are "capable" of burning No. 6 fuel oil if they are "potentially capable", i.e., if they are merely capable of installing equipment which would permit them to burn No. 6 fuel oil.

The Commission rejects this suggestion. Obviously, any facility is capable of installing No. 6 oil burning equipment. If that were the test for being permitted to have a No. 6 ceiling, every facility would qualify for such a ceiling, regardless of whether or not No. 6 oil were actually its alternative fuel. The "potentially capable" test, then, is tantamount to being a proposal to have a uniform No. 6 ceiling rather than a three-tier approach.

Such a proposal should be considered directly and on the merits. The Commission does that not only herein but in a companion order issued today in this docket. As has been discussed above and as is discussed in the companion order, the Commission is very concerned about the three-tier approach giving rise to uneconomic investment in No. 6 fuel burning equipment. Accordingly, the Commission has transmitted to Congress an exemption rule which would hold the upper two tiers of the three-tier approach in abeyance until November 1, 1980.

The Wisconsin Public Service Commission commented that the words "technically capable" as used in the proposed regulation are ambiguous. They do not make it clear whether the equipment needed to burn No. 6 oil must be actually in place to qualify for a No. 6 ceiling or whether there only must be the potential to install the equipment. The Wisconsin Commission urged that the regulations be reworded to require that the No. 6 capability be actually installed. Additionally, the Wisconsin Commission urged that it be required that the equipment have been in place for three years for a facility to qualify for a No. 6 ceiling.

In response to the Wisconsin Commission's comment, the regulation shall be clarified so that it is clear that there must be an actual, installed capability to burn No. 6 fuel oil. The Commission will not require that such equipment have been in place for three years, however. To do so would have the result that facilities which had recently installed No. 6 capability would be incrementally priced at the No. 2 level. Since they have the capability to use No. 6 fuel oil, they would then be likely to switch to No. 6 oil and would be lost as contributors toward recovery of system costs.

B. Different Grades of Oil Used at the Same Industrial Facility

AGA commented that, at some facilities different grades of oil are used in different boilers. AGA suggested clarification concerning what could be certified as being the alternative fuel capability of such a facility. Both the regulations in the Notice of Proposed Rulemaking and the regulations adopted herein contemplate permitting users to certify on the basis of the lowest priced grade of oil they can burn at their industrial boiler fuel facility.

C. State Agency Certification of Alternative Fuel Capability

NARUC suggested having state agencies file certifications of alternative fuel capability in lieu of having industrial users filing the certifications. This, however, would be needlessly circuitous. The end-users would have to inform the state of the user's alternative fuel capability just so the state could communicate that information to the FERC. It is more direct to have the information filed with the FERC.

NARUC further suggested that, if the Commission determines to have certifications filed directly with the FERC, affiants should be required to file a copy with the relevant state Commission. The final regulations have been revised to accommodate this suggestion.

D. Public Inspection of Alternative Fuel Capability Affidavits

A large number of distributors objected to the requirement that customers' certifications of alternative fuel capability be available for public inspection at the distributor's office. Insofar as the certifications will be available to the public through the Commission's Office of Public Information, this requirement will be dropped.

A number of commenters suggested that the public be denied access to filed alternative fuel capability affidavits. This, however, would be of dubious legality and would effectively preclude the possibility of there being protests of industrial users' certifications of alternative fuel capability.

E. Protest Procedure

The Columbia Gas Distribution Companies suggested that the Commission provide a time limit for filing protests of certifications of alternative fuel capability. The Commission observes, however, that the protest procedures available to the public for purposes of protesting a certification are the procedures which are available under Section 1.10 of the Commission's regulations. Under that section, a protest is "intended solely to alert the Commission and the parties to a proceeding of the facts and nature of the protestant's objection. . . ." No sufficient reason has been advanced for putting a time limit on the period during which a party may bring to the Commission's attention a matter regarding a certification of alternative fuel capability. It would be contrary to the public interest to restrict the effectiveness of protests as an enforcement tool.

VII. Subsidiary Issues

There are several remaining issues regarding modification of the proposed regulations. First, AGA and several others suggested that the term "facility" be defined. The Commission shall so provide.

Secondly, several parties suggested that alternative fuel price ceilings be published less frequently than monthly. They expressed the view that less frequent publication would permit greater rate stability and would permit more data to be collected prior to the publication of a ceiling. The Commission, however, shall retain the requirement that ceilings be published on a monthly basis. Oil prices are so volatile that if there were longer publication period (e.g., quarterly or semiannually) there would be a danger that a ceiling would become either excessively low or high before the publication of the subsequent ceiling.

Lastly, several parties urged that the Commission adopt procedures by which an industrial facility could obtain a ceiling lower than that which would otherwise be applicable to that facility. It was suggested that the regulations provide that if an incrementally priced industrial customer could demonstrate that it would be able to purchase oil at a price below the applicable ceiling, that customer would not be incrementally priced above the level of the price at which it would be able to purchase the oil.

The Commission shall decline to adopt this proposed "failsafe" procedure. The Commission is concerned about a procedure which would depend upon gas customers obtaining prices from oil sellers not for the primary purpose of buying oil, but for the purpose of lowering gas rates. Further, the Commission observes that ceiling prices will be adjusted downward from the weighted average in a manner designed to ensure that the ceilings on incremental pricing will be below oil prices so as to prevent fuel switching. This obviates the need for the proposed "failsafe" procedure.

VIII. EIA Data Collection and Computation of Ceiling Prices

The Commission has requested the Energy Information Administration (EIA), the data collection agency of the Department of Energy,[20] to gather the data necessary to determine alternatvie fuel prices charged to industrial users in each region and to process that data in order to arrive at three ceiling levels for each incremental pricing region.

In the May 11, 1979 Notice of Proposed Rulemaking, it was proposed that each month data would be collected from fuel oil sellers regarding the prices they charge for No. 2 fuel oil, No. 6 high sulfur fuel oil and No. 6 low sulfur fuel oil. The price data would be for volumes delivered to large, non-utility industrial users which purchase on a large lot or contract basis. Price data would not include state or local sales taxes.

The May 11 Notice further proposed the method by which EIA would derive alternative fuel price ceilings from the data. For each region an average price, weighted by volumes, would be calculated for each of the three alternative fuels. Weighted average prices would then be adjusted downward by two standard deviations. For each region, the weighted average price for each fuel, as adjusted, would be compared to the lowest reported actual price for such fuel. The higher of these would be established as the alternative fuel price ceiling for that fuel for the region.

In its May 11 Notice, the Commission stated its belief that any lag between the collection of data and the publication of ceiling prices should be minimized. EIA had informed the Commission that the collection and analysis of data for any given month would require approximately 45 days processing time. Accordingly, the Commission requested that ceiling prices be available within 45 days after the close of the month for which data is collected, but not later than 15 days prior to the first day of the month for which the ceiling prices would be applicable. Thus, data collected for October, 1979 would have to be published in the form of ceiling prices by mid-December, 1979.[21] The ceiling prices would be published in the Federal Register and would be available through the FERC Office of Public Information.

Commenters raised a number of issues regarding the method of collecting oil price data and the generation of ceiling prices from that data. Those issues are discussed below.

Unlike the proposed regulations, the final regulations do not contain a description of the method to be followed by EIA in collecting data and generating ceiling prices. If the regulations were to tie EIA to a rigid procedure, EIA and the Commission would lack the flexibility to quickly adjust data collection and analysis techniques to accommodate any unforeseen problems as soon as they arise. Thus, data collection and analysis issues considered below are discussed not because they affect the final regulations, but because it has been the policy in this proceeding to keep the participants informed to the fullest extent possible about all aspects of the incremental pricing program. Accordingly, the following discussion is for informational purposes.

A. The Lag Between Collection of Data and Publication of Ceiling Prices

Many commenters stated that the major problem with the proposed procedures for EIA was the two month lag between the end of the month for which data would be collected and the beginning of the month for which ceiling prices would be effective.

The Commission requested comments on this potential lag problem in its Notice of Proposed Rulemaking, recognizing that prices for heavy oils usually decline in the summer months and escalate in the winter months. Under the proposed data collection procedures, April fuel oil prices would form the basis of ceilings for July. By then, however, industrial customers might be able to purchase fuel oil at a lower cost, in which case they would be likely to switch to oil.

The Commission requested comments on the extent to which there is a seasonality problem with the two month lag, and on whether any additional adjustments would be required or whether the proposed "two standard deviation" downward adjustment method would adequately compensate for the problem.

There was widespread agreement among the commenters that there is a serious problem with having ceiling prices based on data for oil sales made two months previously. There is not only a seasonality problem but also the more general problem that oil prices can fluctuate dramatically at any time of the year. OPEC cartel control of world oil prices has severely disrupted formerly well-established seasonal trends in oil prices. There can now be a substantial rise or drop in oil prices that is entirely unrelated to seasonality. Thus, it would be inaccurate to consider only earlier seasonal trends in developing an adjustment factor to compensate for the lag in publishing ceiling prices.

Commenters suggested a variety of solutions for the lag problem. Recognizing that some lag is inevitable using the data collection techniques described in the Notice of Proposed Rulemaking, several commenters suggested that those techniques be abandoned altogether and that posted oil prices be used instead. The problem with using posted oil prices, however, is that they are not consistently available for the various incremental pricing regions for all three grades of oil—No. 2, No. 6 high sulfur, and No. 6 low sulfur. More importantly, the data and methodology underlying posted prices are not subject to examination and verification by the Commission.

Another suggestion was to apply a flat percentage downward adjustment, e.g., 15 percent, after the "two standard deviation" adjustment methodology is applied to the weighted average oil prices derived from EIA's data. This, it was argued, would adequately adjust for the lag problem. Choice of a percentage adjustment factor would be arbitrary, however. Further, a flat percentage adjustment would sometimes lead to such a low incremental pricing ceiling that the benefits of incremental pricing to residential and commercial customers would be drastically reduced or even eliminated. Lastly, there could be no assurance that such an adjustment would in all cases adequately compensate for the lag problem.

A third suggestion was to retroactively adjust ceiling prices after the actual oil prices for a month are known. There would then be a further surcharge or refund depending on whether the retroactive adjustment was positive or negative. This, however,

[20] Section 508(b) of the NGPA vests in the Commission, for purposes of carrying out the functions vested in it by the NGPA, all of the authority vested in the Secretary of Energy by section 301(a) of the DOE Organization Act, which encompasses the authority set forth in section 11(b) of the Energy Supply and Environmental Coordination Act of 1974 and section 13 (b), (c) and (d) of the Federal Energy Administration Act of 1974. This authority will be exercised by the EIA on behalf of the Commission.

[21] EIA has consulted with potential respondents to Form EIA 194, the form which EIA currently proposes to use to gather data for purposes of establishing incremental pricing ceilings. The potential respondents told EIA that they would need more time to complete the form than EIA had allowed when EIA made its original estimate that 45 days would be required for the collection and analysis of data for any given month.

Accordingly, five more days will be allowed for collection and analysis of data so that respondents can have an additional five days to return Form EIA-194. The final regulations will require that alternative fuel price ceilings shall be published on the 20th of each month, not the 15th, so that 50 rather 45 days will be permitted for collection and analysis of data for each month.

would lead to a constant and undesirable instability of rates.

A fourth suggestion was to have state agencies generate the ceilings. There is, however, no indication in the record that state or local authorities would not have the same lag problems EIA will have. Further, it is unclear that more than a handful of states would take on the task of generating timely data.

A fifth suggested solution was to use a point which was three standard deviations removed from the weighted average as the ceiling price. Such an approach, however, would lead to a ceiling price which would be lower than all but a tiny fraction of the oil prices observed during a month (about 0.13% in the case of perfectly normal distribution). Any skew to the right would lead to a situation in which the lowest price woud determine the ceiling price every time.

Another suggestion was to develop a mechanism which would use current oil price trends to adjust ceiling prices to reflect current market conditions. The Commission has used this concept in developing an adjustment mechanism to correct for lag.

The correction factor operates by tracking trends in oil prices derived from data not subject to the time lag. Each of the ceiling price data collected by EIA will be multiplied by the ratio of current posted oil prices to posted prices from two months previous. This correction factor is intended to be an estimate of *change* in prices (up or down) and not an accurate measure of what large industrial users are actually paying. Thus, it is not necessary that the quality of the data be as high as that of actual ceiling price data, and concerns regarding sample size and statistical validity are greatly reduced.

The prices (both current and those observed at the time of the ceiling price data collection) needed for the correction factor will be obtained by using posted prices. Use of EIA data or EIA publications is not possible because the data obtained from them would be subject to the same time lag problems as the uncorrected ceiling price data. In view of the ease with which posted prices may be obtained, they are clearly the best alternative.

Platt's Oilgram will be used as the source of posted price data. Comments suggested several publications of posted oil prices, but we believe Platt's Oilgram provides the most timely and geographically diverse information.

The prices found in Platt's Oilgram are given each trading day in the form of high and low prices for each oil product in each of the cities for which Platt's Oilgram publishes prices. The low price will be used for determining the correction factor. Furthermore, because there are not enough data available to compute separate correction factors for low sulfur residual fuel oil, correction factors will be computed for residual fuel oil without regard to sulfur content. This can be done since the correction factors are designed to reflect percentage changes in oil prices, not price levels themselves.

As for the number of correction factors which will be generated for residual fuel oil, the Commission has determined that it would not be possible to have a correction factor for each of the 79 incremental pricing regions, since posted prices for No. 6 fuel oil are unavailable for most of the regions. Instead, there will be two correction factors, one for the area west of the Rockies and another for the area east of the Rockies.[22]

The reason for having a separate correction factor for the West Coast is that it is a markedly distinct oil market area with separate sources of supply. Analysis of petroleum movement by the Congressional Research Service of the Library of Congress, as published by the U.S. Geological Survey, indicates that the West Coast is supplied from indigenous sources and from landings at West Coast ports. There is apparently little residual oil flow across the Rockies.

Additionally, oil price changes on the West Coast appear to move independently from the rest of the country. The Commission compared a series of posted prices for residual oil (2.8 percent sulfur maximum) in the New York City harbor area with comparable series (3.0 percent sulfur maximum) for the Los Angeles/San Francisco area. The two series covered 144 trading days, running from the last day of 1978 to August 2, 1979. This interval includes the period of recent oil price increases as well as a seasonal shift from winter to spring. Analysis of these data [23] has led to the conclusion that trends in West Coast residual oil price changes are significantly different from those occurring on the East Coast.

The Commission has considered having separate correction factors for the Gulf Coast, the Rocky Mountain area and the Midwest. It was decided not to have a separate factor for the Gulf Coast because residual oil price trends in that area appear to be very similar to East Coast trends. Just as it compared a series of New York prices to West Coast prices, the Commission compared the same series of New York prices to a comparable series for the Gulf Coast area. Unlike West Coast No. 6 oil prices, Gulf Coast prices appear to move in tandem with prices on the East Coast.

It was determined that there should not be a separate correction factor for the Rocky Mountain area because posted prices are unavailable for it.

There will not be a separate correction factor for the Midwest because oil is supplied to that region largely from the Gulf Coast. Additionally, there are only four posted prices for the Midwest. These four do not move together as closely as would be expected if there were a unified Midwestern residual oil market.

Since a correction factor composed of the ratio of prices for only two days which are two months apart may not accurately reflect underlying trends, each of the two correction factors for residual oil prices will be based on the ratio of average posted prices for 10 recent days to average posted prices for the 10 days occurring two months previous. Use of 10 day averages rather than posted prices for a single day provides a more accurate measure of basic trends since averaging will smooth the irregular nature of oil price changes.

The Commission recognizes that inclusion of too many days in the moving average would dilute the more current observations with stale data, and the correction factor would fail to reflect the most recent developments. An examination of samples of price data led to a determination that 10 trading days (two weeks) of data is the optimum number of days to be included in the moving average in order to reduce the effects of aberrant prices without undue loss of currency.

Turning now to No. 2 oil, a separate correction factor will be calculated for each incremental pricing region. This is possible because posted prices for No. 2 oil are available for many more locations than are posted prices for residual fuel oil, especially in the West Coast and Rocky Mountain areas.

An attempt to divide the nation into several large regions similar to the two regions for the residual oil correction factor was unsuccessful. Distillate fuel oil, unlike residual oil, can be transported easily by pipeline, rail, and truck as well as by barge and tanker, the principal means of transporting No. 6 fuel oil. Thus, the national market for No. 2 fuel oil is unified to a considerable extent. However, while there are no

[22] The Western correction factor will apply to six metropolitan regions, Phoenix (Region 26), Los Angeles (Region 27), San Diego (Region 28), Seattle-Takoma (Region 29), Portland (Region 30), and San Francisco (Region 31), and it will apply to the states of Arizona, California, Nevada, Oregon and Washington.

[23] Appendix B contains an analysis of this data series.

significant differences in price trends among the large regions of the country, there are many smaller differences among individual cities and states.

Thus, the Commission has determined to develop a correction factor for each of the incremental pricing regions. Prices are posted for 19 of the 31 metropolitan incremental pricing regions.[24] For most of the remaining metropolitan regions, the factor computed for the state in which the metropolitan region is located can be used. If a metropolitan region overlaps state lines, the metropolitan area will be associated with the state in which the principal city of the metropolitan area is located. Thus, for example, the Cincinnati metropolitan area, which includes areas in Ohio, Kentucky and Indiana, will be associated with Ohio.

Two exceptions will be Region 2 (Hartford) and Region 28 (San Diego). The posted prices for New Haven and Los Angeles appear to be the most reasonable choices to use for developing correction factors for, respectively, Hartford and San Diego.

With regard to the states, Platt's Oilgram provides data for 32 cities which fall within a total of 27 states. In addition to those data, Platt's also lists posted prices for No. 2 fuel oil delivered to Midwestern terminals. Two other prices are listed for shipments in the South Central multistate region. Considering all of the data, prices are available for all but 14 of the contiguous 48 states. For those states without posted price data, values will be derived from the associated multistate region, taking into consideration all prices posted for that region.

The posted price data covers the multistate regions reasonably well, with three quotes for Region A (New England), five quotes for Region B (Mid-Atlantic), nine quotes for Region C (Southeastern), six quotes for Region E (Great Plains), five quotes for Region F (South Central), four quotes for Region G (Rocky Mountain) and four quotes for Region H (Pacific Coast). There were, however, only two quotes for Region D (Midwestern). The problem of there being so few observation points for Region D (Midwestern) can be alleviated by including, for correction factor purposes, the posted prices for Region 11 (Pittsburgh), Region 20 (St. Louis), and Region 22 (Minneapolis-St. Paul).

Finally, since many of the correction factors for No. 2 fuel oil will be computed from posted prices for only a single city, the moving average for computing the distillate fuel oil correction factors will be expanded to 15 trading days in order to minimize the effect of random aberrations due to short-term price changes.

B. Data To Be Collected

A number of issues were raised about the type of data which EIA should collect.

1. *Spot Market Data.* The proposed regulations indicated that only contract sales data would be collected by EIA. Cincinnati Gas & Electric Company supported this. A majority of the commenters which addressed the issue, however, urged that spot market data be collected as well.

In support of the argument that both spot market and contract data should be used by EIA, the commenters noted that it is no longer true that spot market prices tend to equal contract prices over the long-term, as stated in the Notice of Proposed Rulemaking. Further, PG&E stated that many of its gas customers which switched to fuel oil during the past few years did so on the basis of spot market, not contract, prices. PG&E observed that purchases on the spot market are made when the spot market price of fuel oil has fallen below the contract price of oil, and that there is a return to the use of gas when spot market prices exceed the contract price of oil.

INGAA stated that in some regions where the spot market is the dominant market for oil purchases, a failure to reflect spot purchases in ceiling prices could create a situation in which spot oil sales could undercut the incremental pricing ceiling. Natural Gas Pipeline Company of America (Natural) suggested that excluding spot market prices from the data collected by EIA may create an incentive for spot prices to be set lower than contract price in order to capture certain "swing" gas and oil loads.

In light of these and other, similar comments, the Commission finds that spot market oil prices should be collected by EIA in addition to contract market data.

2. *Transportation Costs.* In the Notice of Proposed Rulemaking it was proposed that transportation costs be included in the oil price data collected by EIA. Thus, the data would reflect the price charged for oil as delivered to the buyer's terminal. Nearly all commenters addressing this issue supported the proposed approach. AGA observed, "This approach ensures true comparability with the actual prices of potential alternate fuels in the market place. . . ."

The Michigan Public Service Commission urged, however, that transportation costs be excluded from collected oil price data because, given the large multistate regions proposed in the Notice of Proposed Rulemaking, transportation costs could vary markedly within a given region. In response, the Commission notes that transportation costs can be an important part of the delivered cost of oil. If transportation costs were not reflected in deriving ceiling prices, those ceilings would be unnecessarily low. In any event, however, the problem to which Michigan alludes is alleviated by the fact that ceilings will be published for states.

3. *Buyer or Seller Data.* In the Notice of Proposed Rulemaking, the Commission proposed that data would be collected from oil sellers rather than buyers. This approach was generally supported. However, several commenters urged that buyer data be used. They argued that fuel oil sellers would have an incentive to report higher than actual prices so as to permit them to undercut incrementally priced natural gas sales.

The Commission shall continue to request that EIA collect data from sellers. As explained in the Notice of Proposed Rulemaking, there are two reasons for taking this approach. First, the EIA currently collects data on No. 2 prices on a regular basis, and this collection effort can be adapted to the requirements of the incremental pricing program. Second, it is EIA's experience that collection of price data from end-users of a product is very difficult. If they do not respond voluntarily, enforcing compliance is a lengthy and burdensome task. These two reasons for collecting data from oil sellers continue to have validity.

As for the argument that sellers may have an incentive to misreport, EIA is alert to the potential problems inherent in there being a reporting burden which may be contrary to the respondent's interest. And in any event, the Commission notes that oil buyers as well as sellers may have an incentive to misreport the prices they are paying for fuel oil: if buyers report low prices, they may be able to lower their potential price for natural gas.

4. *Large Lot Sales Data.* No. 6 fuel oil is typically sold only to large customers in large quantities and is priced on such a basis. No. 2 fuel oil sold for boiler fuel use in large industrial facilities is also sold in large quantities and priced accordingly. Thus, since the first phase of the incremental pricing program involves large industrial boiler fuel facilities, it was proposed in the Notice

[24] Regions 1, 3, 4, 5, 7, 9, 11, 12, 17, 19, 20, 21, 22, 25, 26, 27, 29, 30, and 31.

of Proposed Rulemaking that alternative fuel price ceilings would be based on data reflecting large, bulk lot industrial sales.

In their comments, United Distribution Companies and Natural suggested that "large lot sales" be defined as those sales of amounts in excess of 6,000 gallons. They argued that is the normal size of a railroad tank car. The Commission shall, however, request that EIA collect data on sales in lots of over 4,000 gallons, the amount EIA has assumed it would use to determine what constitutes a "large lot" sale. If 6,000 gallons were the determinant, many full load truck deliveries would be excluded from EIA's data base.

C. The Derivation of Ceilings From Collected Data

1. *Averaging and Adjustments: The "Two Standard Deviation" Approach.* The proposed regulations provided that the weighted average prices determined by EIA would be adjusted downward by two standard deviations. The price which is two standard deviations removed from the mean would be the ceiling price for incremental pricing purposes, unless that price is lower than the lowest observed price for the respective grade of oil in the region. In that event, the lowest reported price would be the ceiling.

Most commenters who responded to the two standard deviation proposal were in favor of such an adjustment. Several commenters had alternative suggestions, however. AGA recommended that three standard deviations be used instead of two. As mentioned above, however, a point which is three standard deviations removed from the mean is so low that the lowest observed price would almost invariably determine the ceiling each month.

The Public Utilities Commission of Ohio and several others, in turn, suggested simply that the lowest observed price be used without there being any determination of a point which is either two or three standard deviations removed from the mean. The Commission shall not adopt an approach which would have the lowest observed price alone determining the ceiling, however. Use of the lowest observed price as the ceiling would not only lead to an erratic series of ceiling prices but would also leave open the distinct possibility of price manipulation.

The California Public Utilities Commission suggested an innovative alternative to the two standard deviation approach. Under the California method, all observed sales volumes would be ranked in ascending order by price. The point below which two and one half percent of the observed volumes occurred would then be determined. The sales price of the oil located at that point would then determine the incremental pricing ceiling. Thus, 97.5 percent of the observed oil sales volumes would have been sold at or above the derived ceiling price.

Should the oil price data be distributed in an approximately normal or "bell" shaped curve, the 97.5 percent approach would produce a result equivalent to that produced by the two standard deviation approach. But should the oil price data be distributed so that the curve is skewed to the right, as the Commission expects will occur most frequently, the two standard deviation approach would result in setting the ceiling price lower than it would be set under the 97.5 percent approach. However, in the event of a sharp skew to the left, the 97.5 percent approach could result in a lower ceiling.

Two principal arguments were advanced in favor of the 97.5 percent approach. First, it was said that the approach was simple, unambiguous and easy to execute. Secondly, no matter what the ultimate shape of the data distribution, the 97.5 percent approach would result in neither the possible exclusion of more than 2.5 percent of observed oil sales, nor a ceiling price set below the lowest reported price.

A closer examination of the 97.5 percent approach reveals a number of serious problems, however. For example, a single, low priced industrial sale could easily comprise the lowest priced two percent of the total volumes observed in a given region. This two percent would be ignored in setting the ceiling price by the 97.5 percent approach. Only the next one half percent would matter. But suppose, in a subsequent month, the large industrial purchased three percent of the total volumes observed. For that month, this single oil customer would determine the ceiling price. If the customer happened to purchase oil at an atypically low price, the resulting ceiling price would drop dramatically from the previous month. Thus, the 97.5 percent approach could lead to the ceiling fluctuating eratically, depending on slight changes in a single customer's consumption.

More importantly, since only the price of the lowest two and one half percent of observed volumes would be considered in determining a ceiling price, a single customer purchasing two and one half percent of the volumes could manipulate the ceiling prices. The Commission does not believe that such an unstable and potentially manipulatable ceiling price would be conducive to the smooth and proper operation of the incremental pricing program. The two standard deviation approach, by making full use of all reported data, would provide a more stable ceiling price and, most importantly, would substantially reduce the possibility of manipulation of ceiling prices.

Several commenters doubted the workability of the two standard deviation method. They expressed concern regarding the complexity of the mathematics of working with weighted data. All calculations will, however, be done by computer and thus the computational effort is not at issue.

A further argument was that the use of weighted data would produce mathematically invalid results in the derivation of a two standard deviation adjustment. However, concerns such as possible dependence among some of the data or a loss of degrees of freedom are misplaced. The results of the two standard deviation adjustment are valid for the purpose for which they shall be used. The downward adjustment by two standard deviations is designed merely to reflect the prices actually paid by industrial users of oil. The adjustment is not intended to serve as a statistical test. Nor is there any attempt to draw a statistical inference from the data. Accordingly, it shall be adopted.

2. *Conversion Factor.* Subsection 204(e) requires that alternative fuel price ceilings be stated on the basis of Btu's. The prices which EIA will collect will typically be on a per barrel basis. Thus, a conversion will be required. The EIA has utilized, over time, standard conversion factors of 5.8 million Btu's per barrel of No. 2 fuel oil and 6.3 million Btu's per barrel of No. 6 fuel oil in converting prices of various fuel to place them on a comparable basis. In the Notice of Proposed Rulemaking, the Commission stated that it anticipated that EIA would continue to utilize these factors.

AGA commented that there may be some variations in the Btu content of oil and urged that there be a downward adjustment factor to accommodate it. The Commission notes, however, that any need for such an adjustment factor will be substantially eliminated by the "two standard deviation lowest price" adjustment factor discussed above.

Other commenters urged that conversion factors be modified to reflect more than merely the Btu content of oil. The commenters pointed out that oil is more efficient to burn in a boiler than gas: it takes slightly more Btu's of natural gas than fuel oil to perform the same amount of work.[25] They urged that the conversion factors mentioned in the Notice of Proposed Rulemaking be modified to reflect the different combustion efficiences between oil and gas.

While gas may be slightly less efficient than oil, there are, on the other hand, a large number of reasons why a purchaser may prefer gas to oil. For example, gas burns cleanly, it does not require storage tanks and it is less destructive of refractory brick than is oil. To take into account efficiency without taking into account these other factors which may enter into a purchaser's decision would be one-sided. Yet, to develop a conversion factor which would adequately reflect all considerations affecting a purchaser's decision would be an impossible task.

Furthermore, such a conversion factor would be beyond the scope of subsection 204(e) of the NGPA. The ceiling is to be expressed in terms of "the price per million Btu's" for fuel oil. There is no mention of adjusting the ceiling up or down to reflect efficiency ratios or other similar consideration that may affect a buyer's decision.

(Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, Subchapter I of Chapter I of Title 18 of the Code of Federal Regulations is amended in Part 282 by the addition of Subpart D as set forth below to be effective December 1, 1979.

By the Commission.

Lois D. Cashell,

Acting Secretary.

Appendix A

Note.—This appendix will not appear in the Code of Federal Regulations.

Federal Energy Regulatory Commission; Washington, D.C.

Alternative Fuel Capability Affidavit

[Docket No. RM79-21]

Participation is Voluntary. Copies of executed alternative fuel capability affidavits filed with the Commission shall be available through the Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

[25] Pacific Gas and Electric Company (PG&E) explained that this burning efficiency differential arises from the chemical composition of the two fuels. Fuel oil contains relatively less hydrogen than does natural gas. Upon combustion, fuel oil loses relatively less useful heat through the formation of water vapor. Consequently, it is slightly more efficient with respect to the amount of useful work that can be derived.

Please Read before Completing This Affidavit

Purpose

The Natural Gas Policy Act of 1978 (NGPA) requires the Federal Energy Regulatory Commission to determine the appropriate alternative fuel price to be used for establishing the price ceiling for certain categories of industrial boiler fuel sales of natural gas. Each nonexempt industrial boiler fuel facility, for purposes of determining the applicable alternative fuel price ceiling, will be deemed to have No. 2 fuel oil as its alternative fuel to natural gas unless it has certified its capability to burn No. 6 high sulfur fuel oil, No. 6 low sulfur fuel oil or No. 5 fuel oil under its boilers by filing this affidavit in compliance with the general instructions below.

Notice

If you do not complete and return this affidavit, the alternative fuel capability of your facility shall be deemed to be No. 2 fuel oil and the surcharge calculated under the incremental pricing program will be based on a No. 2 fuel oil ceiling price.

General Instructions

If alternative fuel capability for a non-exempt boiler fuel facility is claimed, this affidavit should be completed and signed, under oath, by a responsible official associated with the facility. A separate affidavit must be filed for each facility for which an alternative fuel capability other than No. 2 fuel oil is claimed.

The original and five copies of the affidavit should be submitted to: Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

Also, one copy must be submitted to your natural gas supplier. Additionally, each industrial facility shall retain such records, documents and data which formed the basis for the certification for a period of three years. Suitable records would include, for example, bills for the installation of the alternative fuel equipment, a qualified engineer's report that alternative fuel capability is in place and bills for purchases of No. 6 or No. 5 fuel oil.

If you have any questions concerning this affidavit contact Ms. Alice Fernandez on (202) 275-4406.

Definitions

(1) "Natural gas supplier" means an interstate pipeline or a local distribution company.

(2) "Local distribution company" means any person other than an interstate pipeline that receives gas directly or indirectly from an interstate pipeline and which is engaged in the sale of natural gas for resale or for ultimate consumption. A person is not considered as having received gas directly or indirectly from an interstate pipeline if the only service performed by an interstate pipeline for the purchaser is a transportation service.

(3) "Boiler fuel use" means the use of any fuel for the generation of steam or electricity.

(4) "Facility" means all buildings and equipment located at the same geographic site which are commonly considered to be part of one plant, mill, refinery or other industrial complex.

(5) "Industrial facility" means any facility engaged primarily in the extraction of processing of raw materials, or in the processing or changing of raw or unfinished material into another form or product.

(6) "Non-exempt industrial boiler fuel facility" means any industrial boiler fuel facility other than any such facility which has been exempted from the provisions of the incremental pricing program in accordance with Part 282 of the Commission's rules and regulations.

(7) "Alternative fuel capability" means installed capability to burn No. 6 fuel oil and to use it on a regular basis.

(8) "High sulfur fuel oil" means any oil containing more than one percent (1.0%) sulfur content by weight.

(9) "No. 2 fuel oil" means No. 2 oil as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM D 396-78.

(10) "No. 5 fuel oil" means either light or heavy No. 5 oil as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM D 396-78.

(11) "No. 6 fuel oil" means No. 6 oil as defined in the standard specification for fuel oils published by the American Society for Testing and Materials, ASTM D 396-78.

(12) "Low sulfur fuel oil" means any oil containing one percent (1%) or less sulfur content by weight.

1. Name of company or organization:——.

2. Name of facility:——.

3. Address: Number——street——, city/town——, county——, State——Zip Code——.

4. Name of natural gas supplier:——.

5. You may claim a price ceiling other than the price of No. 2 fuel oil if any non-exempt boiler within your facility has the capability to burn a No. 6 or No. 5 fuel oil as an alternative fuel and you check the appropriate box below.

(a) ☐ Has installed capability and is legally permitted to burn No. 6 low sulfur fuel oil.

(b) ☐ Has installed capability and is legally permitted to burn No. 6 high sulfur fuel oil.

(c) ☐ Has installed capability and is legally permitted to burn No. 5 fuel oil.

6.0 Description of records, documents and data substantiating the above claim: ——

————

————

————

————

Dated: ——.

(Signature) ——

Person Completing this Affidavit:

Name ——

Title ——

Phone No. ——

Subscribed and sworn to before me this —— day of ——.

Notary Public ——

Apppendix B

Note.—This appendix will not appear in the Code of Federal Regulations.

Staff Analysis to Determine the Number of Correction Factors Needed In Generating a Residual Oil Correction Factor

The Commission's staff collected posted prices for residual oil based on the assumption that regional correction factors would be needed to reflect trends on the East Coast, West Coast, and Gulf of Mexico and in the Midwest. Having a correction factor for the Midwest was eliminated for the reason given in the body of this order.

On the West Coast, Platt's Oilgram reports a daily price for residual oil in the Los Angeles/San Francisco (LA/SF) area. On the East Coast, prices are reported for approximately 12 cities, although some prices are for residual oil with specified sulfur content. A price is quoted for the Gulf of Mexico area as well as specified price for New Orleans.

Staff considered the need for three separate regional correctional factors by comparing a series of posted prices for residual oil (2.8 percent sulfur maximum) in the New York City harbor with a similar series of data (3.0 percent sulfur maximum) for the LA/SF region and for the Gulf Coast region. The three series covered 144 trading days, running from the last of 1978 to the 2nd of August, 1979, the last day for which data were available. This interval included the period of recent oil price increases as well as a seasonal shift from winter to spring. In the first step of the analysis, staff found a high degree of correlation between the price series in New York and the other two regions.[1]

In a further analysis, staff considered the daily differences between the New York series and the other two series. The concern was not with the average difference between prices in one region and those in another, but with the variation in the series of differences. Little variation would indicate that price trends in two regions were similar and that separate correction factors would be unnecessary.

For the interval studied, the analysis indicated an average price difference of $1.43 per barrel between New York and the LA/SF region, with New York prices being higher. The standard deviation was 1.34, signifying a good probability that prices in LA/SF would fall between $0.09 and $2.77 less than prices in New York. This level of dispersion is too large to ignore. It indicates that the East and West Coast residual oil markets do not operate with a dependable degree of consonance. Thus, a single correction factor would be inappropriate for both regions.

The series of price data for the New York region and for the Gulf region displayed a more harmonious relationship. The average price difference was $1.98 per barrel, reflecting lower prices in the Gulf region, but, the standard deviation was only 0.49. This result is in accord with the high correlation between New York and Gulf region prices as well as with the fact that East Coast and Gulf region oil markets are linked by extensive trade.[2]

In a final analysis, the entire series of price data for the Gulf region was regressed on the New York data in order to learn more about the relationship between the two data sets.[3] As a result of the analyses, a separate correction factor for the Gulf region appears unnecessary.

[1] The correlation coefficients were 0.871 between New York and LA/SF, and 0.975 between New York and the Gulf region. A high degree of correlation was not unexpected since time series data were being compared, and each series is strongly influenced by the overall worldwide trend in rising oil prices. Moreover, unlike many cross sectional data, these time series are highly autocorrelated in that the price on any given day is influenced by the price on the preceding day. Thus each day's price is not a truly independent observation. In spite of these statistical considerations, the extremely high correlation between the New York and Gulf series indicates the likelihood of close coupling between oil price levels in these regions.

[2] Perspective on the significance of the dispersion in price differences may be gained by looking at the average price change for both the New York and Gulf regions. In New York, the average price change, in either direction, was $0.38 per barrel. In the Gulf region, the average change was approximately the same at $0.41 per barrel. This suggests that much of the dispersion in the differences in prices is due to the size of the price changes themselves, as they occur more or less randomly, rather than to any underlying difference in market behavior. Of course, this observation is of heuristic value only. Further analysis is needed to establish such a conclusion.

[3] $P=0.900+0.929\ P_{Gulf}+e_i$, $R^2=0.951$ NY (0.0793) (0.0177)

The high value of R^2 indicates an overall extremely good fit—the regression line accounts for most of the observed variation in the Gulf prices. Of equal importance for our purpose is the value of the slope, (0.929). Were this parameter found equal to unity, a change in the New York price would, on average, produce an identical corresponding change in Gulf prices. Thus, an additive correction factor would be accurate. In fact, over the time period studied, the estimated slope is found to be slightly less than unity. Although the departure from unity is statistically significant (as evidenced by the very low standard error of the estimated slope), the practical effect is negligible. Not only did the period under study encompass an atypically large surge in oil prices but the multiplicative nature of the proposed correction factor provides for closer agreement.

An example may prove to be helpful. Over the period studied, New York prices averaged $15.246 per barrel. Gulf area prices averaged $13.262 per barrel, 13 percent less. Imagine that, during the time lag between ceiling price data collection and publication, New York prices were observed to rise 5% (a very high annual growth rate of 34% assuming a two month lag). A correction factor of 1.05 would be applied to all prices, bringing the Gulf area to $13.925. Ignoring random errors, the regression indicates that the $0.762 increase in New York translates into a (0.929 x $0.762)=$0.708 increase in the Gulf area. The "true" increase would bring the Gulf price to 13.970. Thus, the correction factor would in fact undercorrect by 4.5 cents per barrel or about 7 mills per MMBtu. This is negligible.

1. The table of sections for Part 282 is amended by the addition of a new Subpart D, entitled "Alternative Fuel Price Ceilings", to consist of §§ 282.401 through 282.405, entitled as follows:

Subpart D—Alternative Fuel Price Ceilings

2. Part 282 is amended by the addition of a new Subpart D, to read as follows:

Subpart D—Alternative Fuel Price Ceilings

§ 282.401 Scope.

This subpart implements section 204(e) of the NGPA and sets forth the method for determining the alternative fuel price ceilings to be used in calculating incremental pricing surcharges on volumes of natural gas delivered for industrial boiler fuel use.

§ 282.402 General Rule.

(a) *Alternative fuel capability.* The alternative fuel capability of each non-exempt industrial boiler fuel facility shall be determined as described in § 282.403.

(b) *Alternative fuel price ceilings.* (1) On December 20, 1979, and on or before the twentieth day of each month thereafter, alternative fuel price ceilings shall be determined and published on the basis of the prices paid by industrial users for No. 2 fuel oil, No. 6 low sulfur fuel oil and No. 6 high sulfur fuel oil for each incremental pricing region in accordance with § 282.404.

(2) The alternative fuel price ceiling which shall be applicable to a non-exempt industrial boiler fuel facility for incremental pricing purposes during any month shall be the ceiling which has been published for that month in accordance with § 282.404 for the incremental pricing region in which the facility is located, except as permitted in § 282.405, and which corresponds to the lowest priced alternative fuel capability of the facility, as determined in accordance with § 282.403.

§ 282.403 Alternative fuel capability of a facility.

(a) *General Rule.* (1) Each non-exempt industrial boiler fuel facility subject to this part shall, for purposes of this part, be deemed to have the capability to use No. 2 fuel oil as an alternative to natural gas, except for those facilities which are certified as having the capability to burn No. 6 high sulfur fuel oil, No. 6 low sulfur fuel oil or No. 5 fuel oil as provided in paragraph (b) of this section. Such certification shall be made by filing an alternative fuel capability affidavit, as provided in paragraph (c) of this section.

(2) A non-exempt industrial boiler fuel facility which is certified as having the capability to burn No. 5 fuel oil shall be deemed, for purposes of § 282.402(b)(2),

to have the capability to burn No. 6 low sulfur fuel oil.

(b) *Certification.* A responsible official associated with a non-exempt industrial boiler fuel facility may certify that the facility has the capability to burn:

(1) No. 6 high sulfur fuel oil, if the facility has the installed capability and is legally permitted to burn No. 6 high sulfur fuel oil on a regular basis;

(2) No. 6 low sulfur fuel oil, if the facility has the installed capability and is legally permitted to burn No. 6 low sulfur fuel oil on a regular basis; or

(3) No. 5 fuel oil, if the facility has the installed capability and is legally permitted to burn No. 5 fuel oil on a regular basis.

(c) *Alternative fuel capability affidavit.* (1) *Commission to provide affidavits.* Alternative fuel capability affidavits referenced in paragraph (a) of this section will be available upon request from the Office of Public Information, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(2) *Availability from natural gas suppliers.* (i) *Initial service of affidavit.* Each natural gas supplier shall mail or otherwise supply an alternative fuel capability affidavit, as described in paragraph (c)(3), of this section, to each facility on such natural gas supplier's system which the natural gas supplier determined to be an industrial boiler fuel facility in accordance with § 282.203 but which the supplier did not determine to be exempt from incremental pricing on the basis of the natural gas supplier's own records.

(ii) *Ongoing availability.* After October 15, 1979, natural gas suppliers shall make alternative fuel capability affidavits available at their principal place of business on an ongoing basis during regular business hours.

(3) *Contents of affidavits.* The alternative fuel capability affidavit shall:

(i) provide the affiant the opportunity to certify that its industrial boiler fuel facility has the installed capability and is legally permitted to burn No. 6 low sulfur fuel oil on a regular basis;

(ii) provide the affiant the opportunity to certify that its industrial boiler fuel facility has the installed capability and is legally permitted to burn No. 6 high sulfur fuel oil on a regular basis;

(iii) provide the affiant the opportunity to certify that its industrial boiler fuel facility has the installed capability and is legally permitted to burn No. 5 fuel oil on a regular basis; and

(iv) require the affiant, either on the affidavit or in an attachment to the affidavit, to describe the records which will be retained under paragraph (h) of this section to substantiate the affiant's certification that the affiant's industrial boiler fuel facility has the installed capability and is legally permitted to burn a No. 6 fuel oil or No. 5 fuel oil on a regular basis.

(4) *Filing.* (i) A certification of alternative fuel capability shall be effective only after an alternative fuel capability affidavit is completed, signed and dated under oath, and filed with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(ii) The affiant shall send a copy of the alternative fuel capability affidavit as filed with the Commission, to the natural gas supplier serving the affiant's facility.

(d) *Effective date of certification.* A properly executed and filed alternative fuel capability affidavit shall determine the alternative fuel capability of the non-exempt industrial boiler fuel facility for which it is filed as of the beginning of the first full month of service after the affidavit is filed with the Commission and received by the facility's natural gas supplier.

(e) *Public availability of certification.* Copies of executed alternative fuel capability affidavits filed with the Commission shall be available through the Office of Public Information, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(f) *Indication on lists of non-exempt facilities.* On any list or revised list of non-exempt facilities filed by a natural gas supplier in accordance with § 282.204, the natural gas supplier shall indicate the alternative fuel capability, as determined in accordance with this section, of each listed non-exempt facility.

(g) *Protests.* Any interested person may protest the alternative fuel capability claimed on an alternative fuel capability affidavit.

(1) The procedures set forth in § 1.10 shall govern the filing of such a protest, except that any person filing a protest shall serve a copy of the protest on the affiant of the alternative fuel capability affidavit.

(2) The affiant may file an answer to any protest. Such answer must be filed within 30 days of the service date of a protest. The affiant shall serve a copy of the answer on the party filing the protest.

(h) *Record retention.* Each industrial user shall maintain books and records to substantiate a certification of alternate fuel capability under this section. Such books and records shall be retained for a period of three years following the date the certification was filed with the Commission.

(i) *Change of circumstances.* (1) For any facility for which an executed alternative fuel capability affidavit has been filed in accordance with this section, if circumstances change so that the facility no longer has both the installed capability and legal permission to burn the alternative fuel oil as was certified in the affidavit, a responsible official of the owner or operator of the facility shall promptly, in writing and under oath, notify the Commission and the natural gas supplier serving the facility of such changed circumstances.

(i) Such notification shall be filed with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and shall be referenced "Changed Alternative Fuel Capability".

(ii) Such notification shall supercede any previously filed alternative fuel capability affidavit so as to determine the alternative fuel capability of the nonexempt industrial facility as of the beginning of the first full month of service after the notification is filed with the Commission and is received by the facility's natural gas supplier. Failure to specify a new alternative fuel capability shall be deemed to indicate capability to burn only No. 2 fuel oil for purposes of this part.

§ 282.404 Alternative fuel price ceilings.

(a) *General rule.* On or before the twentieth day of each month, in accordance with the provisions of § 282.402 and paragraph (b) of this section, alternative fuel price ceilings shall be published for each incremental pricing region as set forth in paragraph (c) of this section. Such ceilings shall be effective for purposes of this part for the month following the month of publication.

(b) *Publication.* (1) Alternative fuel price ceilings shall be published for each of the contiguous 48 states of the continental United States on December 20, 1979, and on or before the twentieth day of each month thereafter.

(2) Alternative fuel price ceilings for each of the 31 metropolitan regions described in the Appendix to this part shall, if possible, be published on December 20, 1979, and on or before the twentieth day of each month thereafter, but, in any event, shall be published no later than October 20, 1980, and on or before the twentieth day of each month thereafter.

(c) *Incremental pricing regions.* (1) As of December 20, 1979, and until the date that alternative fuel price ceilings are published for 31 metropolitan regions, as provided in paragraph (b)(2) of this section, the incremental pricing regions used for purposes of this part shall be each of the contiguous 48 states within the continental United States. For such period of time, the alternative fuel price ceilings applicable to the District of Columbia shall be the ceilings published for Maryland.

(2) After the date that alternative fuel price ceilings are published for the 31 metropolitan regions, as provided in paragraph (b)(2) of this section, the incremental pricing regions used for purposes of this part shall be:

(i) the 31 metropolitan regions; and

(ii) the 48 regions consisting of the area of each of the contiguous 48 states of the continental United States which is not included within any metropolitan region.

§ 282.405 Optional ceilings for service areas.

(a) *General Rule.* (1) If the service area of a local distribution company is geographically unified and extends into more than one of the incremental pricing regions as established in accordance with § 282.404, the local distribution company may use for its service area the alternative fuel price ceilings established for the region in which occur 50 percent or more of the distribution company's deliveries to non-exempt industrial boiler fuel facilities, provided that the distribution company files a certification in accordance with paragraph (b) of this section.

(2) If a local distribution company's service area extends into more than one of the incremental pricing regions, but the company cannot satisfy the requirements of paragraph (a)(1) and paragraph (b) of this section so as to be able to file a certification of dominant region in accordance with paragraph (b) of this section, such local distribution company may petition, in accordance with paragraph (c) of this section, for permission to use for its entire service area the alternative fuel price ceilings established for one of the incremental pricing regions within which the company's service area falls.

(b) *Certification of dominant region.* (1) A certification by a local distribution company as permitted by paragraph (a)(1) of this section must contain:

(i) an attestation that the company's service area is geographically unified and extends into more than one incremental pricing region;

(ii) an attestation that during the 12 month period ending no earlier than four months before the date of the certification, 50 percent or more of the company's deliveries, by volume, to non-exempt industrial boiler fuel facilities occurred within one of the incremental pricing regions into which the company's service area extends; and

(iii) a map showing the company's service area and identifying the incremental pricing regions into which the service area extends.

(2) *Filing.* A certification containing the matter described in paragraph (b)(1) of this section shall be effective only when signed, dated, and filed with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, referenced "Certification of Dominant Region". A copy of such certification shall be sent to the state or local authority having jurisdiction over the local distribution company and to each customer of the local distribution company which the company has identified, as of the date of the certification, as a non-exempt industrial boiler fuel facility.

(3) *Effective date of certification.* A properly executed and filed certification as described in paragraph (b)(1) shall be effective as of the beginning of the first full month of service after the certificate is filed with the Commission.

(c) *Petition.* (1) A local distribution company which seeks to petition in accordance with paragraph (a)(2) of this section may file such petition with the Director, Office of Pipeline and Producer Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. Such petition shall conform to the requirements of § 1.7 of the Commission's Rules of Practice and Procedure.

(2)(i) Petitions filed in accordance with paragraph (c)(1) of this section shall be subject to approval or denial by the Director, Office of Pipeline and Producer Regulation.

(ii) Petitions not granted within 90 days shall be deemed to be denied.

Appendix I—Incremental Pricing Regions

[Note.—This appendix will appear in the Code of Federal Regulations.]

The following are the 31 metropolitan regions which are to be used for purposes of this part:

Region 1 Boston Metropolitan Area
Counties
Essex, Mass.
Middlesex, Mass.
Norfolk, Mass.
Plymouth, Mass.
Suffolk, Mass.
Rockingham, N.H.

Region 2 Hartford Metropolitan Area
Counties
Hartford, Ct.
Middlesex, Ct.
Tolland, Ct.

Region 3 New York Metropolitan Area
Cities
New York City
Counties
Putnam, N.Y.
Rockland, N.Y.
Westchester, N.Y.
Bergen, N.J.
Essex, N.J.
Morris, N.J.
Somerset, N.J.
Union, N.J.
Hudson, N.J.
Nassau, N.Y.
Suffolk, N.Y.
Monmouth, N.J.
Middlesex, N.J.
Passaic, N.J.
Fairfield, Ct.

Region 4 Philadelphia Metropolitan Area
Counties
Bucks, Pa.
Chester, Pa.
Delaware, Pa.
Montgomery, Pa.
Philadelphia, Pa.
Burlington, N.J.
Camden, N.J.
Gloucester, N.J.
Mercer, N.J.
New Castle, Del.
Salem, N.J.
Cecil, Md.

Region 5 Baltimore Metropolitan Area
Cities
Baltimore, Md.
Counties
Anne Arundel, Md.
Baltimore, Md.
Carroll, Md.
Harford, Md.
Howard, Md.

Region 6 Washington, D.C. Metropolitan Area
Cities
Washington, D.C.
Alexandria, Va.
Fairfax, Va.
Falls Church, Va.
Manassas, Va.
Manassas Park, Va.
Counties
Charles, Md.
Montgomery, Md.
Prince George's, Md.
Arlington, Va.
Fairfax, Va.
Loudoun, Va.
Prince Williams, Va.

Region 7 Atlanta Metropolitan Area
Counties
Butts, Ga.
Cherokee, Ga.
Clayton, Ga.
Cobb, Ga.
DeKalb, Ga.
Douglas, Ga.
Fayette, Ga.
Forsyth, Ga.
Fulton, Ga.
Gwinnett, Ga.
Henry, Ga.
Newton, Ga.
Paulding, Ga.
Rockdale, Ga.
Walton, Ga.

Region 8 Tampa-St. Petersburg Metropolitan Area
Counties
Hillsborough, Fla.
Pasco, Fla.
Pinnellas, Fla.
Region 9 Miami Metropolitan Area
Counties
Broward, Fla.
Dade, Fla.
Region 10 Buffalo Metropolitan Area
Counties
Erie, N.Y.
Niagara, N.Y.
Region 11 Pittsburgh Metropolitan Area
Counties
Allegheny, Pa.
Beaver, Pa.
Washington, Pa.
Westmoreland, Pa.
Region 12 Detroit Metropolitan Area
Counties
Lapeer, Mich.
Livingston, Mich.
Macomb, Mich.
Oakland, Mich.
St. Clair, Mich.
Wayne, Mich.
Washtenaw, Mich.
Region 13 Cleveland Metropolitan Area
Counties
Cuyahoga, Oh.
Geauga, Oh.
Lake, Oh.
Medina, Oh.
Portage, Oh.
Summit, Oh.
Lorain, Oh.
Region 14 Columbus Metropolitan Area
Counties
Delaware, Oh.
Fairfield, Oh.
Franklin, Oh.
Madison, Oh.
Pickaway, Oh.
Region 15 Cincinnati Metropolitan Area
Counties
Clermont, Oh.
Hamilton, Oh.
Warren, Oh.
Boone, Ky.
Campbell, Ky.
Kenton, Ky.
Dearborn, Ind.
Butler, Oh.
Region 16 Indianapolis Metropolitan Area
Counties
Boone, Ind.
Hamilton, Ind.
Hancock, Ind.
Hendricks, Ind.
Johnson, Ind.
Marion, Ind.
Morgan, Ind.
Shelby, Ind.
Region 17 New Orleans Metropolitan Area
Parishes
Jefferson, La.
Orleans, La.
St. Bernard, La.
St. Tammany, La.
Region 18 Milwaukee Metropolitan Area
Counties
Milwaukee, Wis.
Ozaukee, Wis.
Washington, Wis.
Waukesha, Wis.
Racine, Wis.
Region 19 Chicago Metropolitan Area
Counties
Cook, Ill.
Du Page, Ill.
Kane, Ill.
Lake, Ill.
McHenry, Ill.
Will, Ill.
Lake, Ind.
Porter, Ind.
Region 20 St. Louis Metropolitan Area
Cities
St. Louis, Mo.
Counties
Franklin, Mo.
Jefferson, Mo.
St. Charles, Mo.
St. Louis, Mo.
Clinton, Ill.
Madison, Ill.
Monroe, Ill.
St. Clair, Ill.
Region 21 Houston Metropolitan Area
Counties
Brazoria, Tx.
Fort Bend, Tx.
Harris, Tx.
Liberty, Tx.
Montgomery, Tx.
Waller, Tx.
Galveston, Tx.
Region 22 Minneapolis-St. Paul Metropolitan Area
Counties
Anoka, Minn.
Carver, Minn.
Chisago, Minn.
Dakota, Minn.
Hennepin, Minn.
Ramsey, Minn.
Scott, Minn.
Washington, Minn.
Wright, Minn.
St. Croix, Wis.
Region 23 Kansas City Metropolitan Area
Counties
Cass, Mo.
Clay, Mo.
Jackson, Mo.
Platte, Mo.
Ray, Mo.
Johnson, Kan.
Wyandotte, Kan.
Region 24 Dallas-Fort Worth Metropolitan Area
Counties
Collin, Tx.
Dallas, Tx.
Denton, Tx.
Ellis, Tx.
Hood, Tx.
Johnson, Tx.
Kaufman, Tx.
Parker, Tx.
Rockwall, Tx.
Tarrant, Tx.
Wise, Tx.
Region 25 Denver Metropolitan Area
Counties
Adams, Col.
Arapahoe, Col.
Boulder, Col.
Denver, Col.
Douglas, Col.
Gilpin, Col.
Jefferson, Col.
Region 26 Phoenix Metropolitan Area
Counties
Maricopa, Az.
Region 27 Los Angeles Metropolitan Area
Counties
Los Angeles, Ca.
Orange, Ca.
Ventura, Ca.
Riverside, Ca.
San Bernardino, Ca.
Region 28 San Diego Metropolitan Area
Counties
San Diego, Ca.
Region 29 Seattle Metropolitan Area
Counties
King, Wash.
Snohomish, Wash.
Pierce, Wash.
Region 30 Portland Metropolitan Area
Counties
Clackamas, Or.
Multnomah, Or.
Washington, Or.
Clark, Wash.
Region 31 San Francisco Metropolitan Area
Counties
Alameda, Ca.
Contra Costa, Ca.
Marin, Ca.
San Francisco, Ca.
San Mateo, Ca.
Santa Clara, Ca.
Napa, Ca.
Solano, Ca.

The following are multistate regions which may be used by the Commission in deriving alternative fuel price ceilings for state incremental pricing regions for which statistically valid samples of oil prices may be unavailable:

Region A New England Multistate Region
Maine
New Hampshire
Vermont
Massachusetts
Connecticut
Rhode Island
Region B Mid-Atlantic Multistate Region
New York
Pennsylvania
New Jersey
Delaware
Maryland
Region C Southeastern Multistate Region
Virginia
North Carolina
South Carolina
Tennessee
Georgia
Florida
Alabama
Mississippi
Region D Midwestern Multistate Region
West Virginia
Kentucky
Ohio
Indiana
Michigan
Illinois
Wisconsin
Region E Great Plains Multistate Region
Minnesota
Iowa
Missouri

Kansas
Nebraska
North Dakota
South Dakota
Region F South Central Multistate Region
Arkansas
Louisiana
Texas
Oklahoma
New Mexico
Region G Rocky Mountain Multistate Region
Montana
Idaho
Wyoming
Utah
Colorado
Region H Pacific Coast Multistate Region
Washington
Oregon
Nevada
California
Arizona

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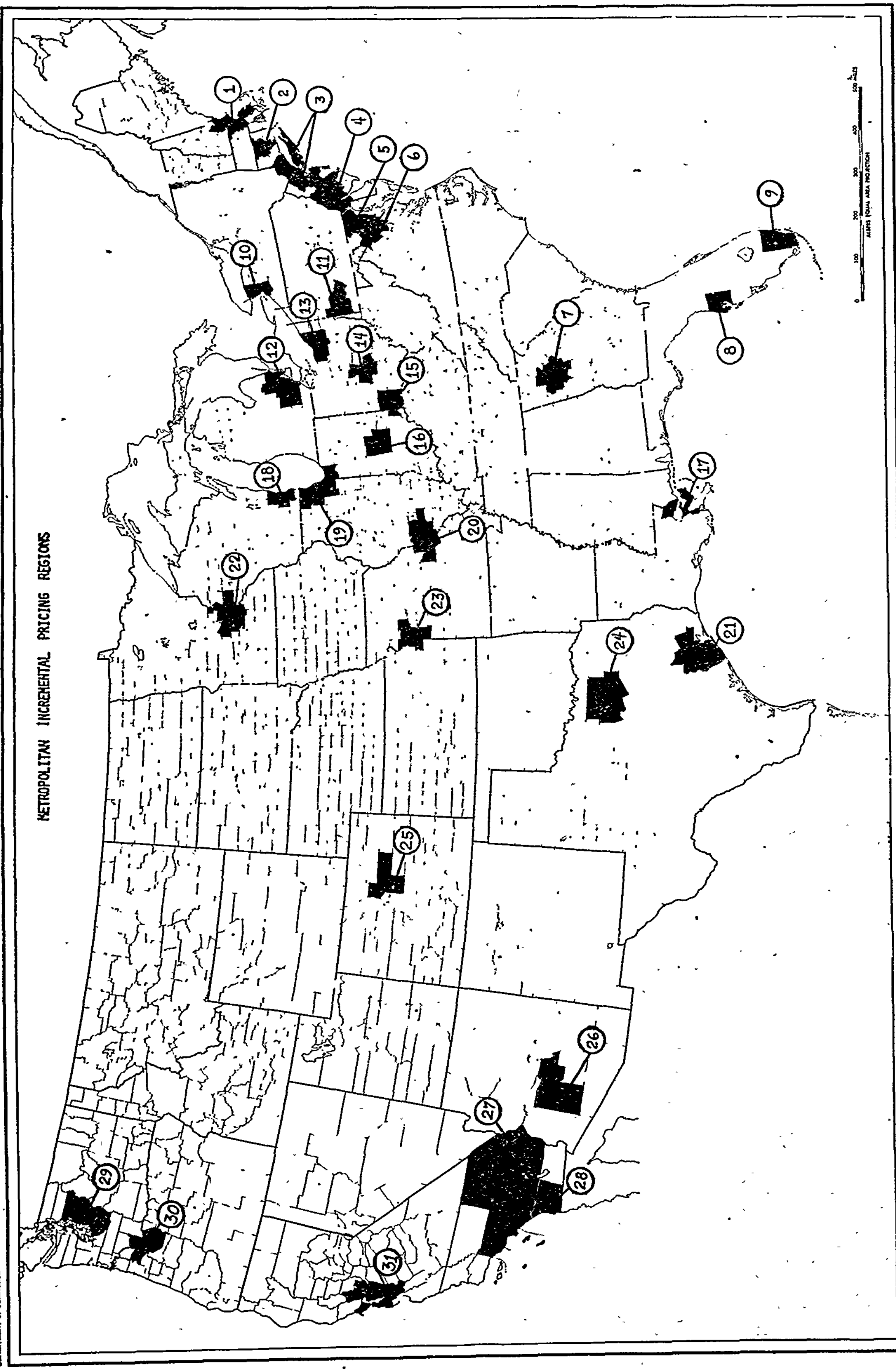

[FR Doc. 79-30757 Filed 10-3-79; 8:45 am]

BILLING CODE 6450-01-C

18 CFR Part 282

[Docket No. RM79-21; Order No. 51]

Rule Exempting Industrial Boiler Fuel Facilities From Incremental Pricing Above the Price of No. 6 Fuel Oil

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule, subject to congressional review.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts a rule which, if not disapproved by either House of Congress, will amend the regulations which set ceilings on the prices which can be charged under the incremental pricing program to large industrial facilities for the natural gas they burn as a boiler fuel. Under this exemptive rule, these large industrial users would be charged a price for their natural gas usage equivalent to the price they would pay for high-sulfur residual fuel oil. This rule will be effective until October 31, 1980.

EFFECTIVE DATE: December 1, 1979, if not disapproved by a Congressional Resolution of Disapproval.

FOR FURTHER INFORMATION CONTACT:

Norman A. Pedersen, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8377.

Nancy E. Williams, Federal Energy Regulatory Commission, Room 8100-F, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8033.

Regulations Implementing Alternative Fuel Price Ceilings in Incremental Pricing Under the Natural Gas Policy Act of 1978.

Rule Exempting Industrial Boiler Fuel Facilities From Incremental Pricing Above the Price of No. 6 Fuel Oil

Issued September 28, 1979.

Section 201 of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. 95-621) requires that the gas used in certain industrial boiler fuel facilities shall be subject to incremental pricing by means of certain surcharges. Section 204 provides, however, that such surcharges may not cause the rates charged for natural gas to incrementally priced industrial facilities to rise above the appropriate alternative fuel price. By this order, under authority of subsection 206(d) of the NGPA, the Commission approves and transmits to Congress a rule affecting the applicable alternative fuel price or ceiling. The rule provides that, until November 1, 1980, each applicable industrial boiler fuel facility shall be exempt from incremental pricing above the level of the price of No. 6 high sulfur fuel oil in the incremental pricing region in which such facility is located.

In a companion "Final Rule" issued today in this docket,[1] the Commission has promulgated a three part ceiling system (three-tier approach). Depending upon a facility's installed capability and legal authority to use certain fuels, an incrementally priced facility would have its ceiling price for natural gas set at the level of the appropriate regional price of No. 2, low sulfur No. 6 or high sulfur No. 6 fuel oil. The Commission found that such a system best met the Congressional purpose embodied in Title II of the NGPA.

However, the Commission also concluded that this system may result in significant investment by facilities in order to install No. 6 capability to gain the advantage of a lower ceiling price for natural gas. The amount of this induced investment cannot be estimated with precision at this time, but the record indicates it could be a sizeable amount. More importantly, the public benefits, if any, that would result from a significant amount of the nation's capital being devoted to this purpose remains unclear. Thus, the Commission is extremely concerned about the three-tier approach becoming effective without more time to gain familiarity with the incremental pricing program, the incrementally priced industrial facilities, and the extent to which the three-tier approach would be likely to result in an inducement to install otherwise unneeded No. 6 oil burning equipment. Therefore, the Commission believes it would be in the public interest to hold the upper two tiers of the system in abeyance for 10 months—from January through October, 1980—to provide a period during which a better understanding of the implications of the three-tier approach can be obtained.

Additionally, implementation of the incremental pricing program would be eased if, at the outset, there were a single rather than a three-tier price ceiling. The Energy Information Administration has encountered difficulties in putting into place the data collection and analysis system which will be necessary under the three-tier approach. The 10 month exemption will ease EIA's task.

The Commission, however, is of the opinion that to provide for a single No. 6 ceiling until November 1, 1980 under authority of section 204(e) may go beyond the Commission's statutory role in implementing section 204.

[1] *Regulations Implementing the Alternative Fuel Price Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978*, "Final Rule", Docket No. RM79-21, issued September 28, 1979.

Consequently, it is issuing this exemptive rule which will go to Congress for its review pursuant to section 206 of the NGPA.

This rule is subject to Congressional review and may be disapproved by either House of Congress. The rule will take effect December 1, 1979 unless, during the first 30 days of continuous session of Congress after a copy of the rule has been submitted to each House of Congress, either House adopts a resolution of disapproval. If, however, Congress permits the exemption embodied in this rule to take effect, the rule shall hold in abeyance until November 1, 1980 so much of the three-tier regulations as are inconsistent with having a high sulfur No. 6 ceiling.

The exemption which this order implements will expire on October 31, 1980. On November 1, 1980 the three-tier approach adopted in the companion Final Rule in this docket will become fully effective, unless that rule is amended in the interim or a further exemption rule is transmitted to Congress and not disapproved.

I. Background

Subsection 204(e) of the NGPA provides that the "appropriate alternative fuel cost" for an industrial facility shall be the price paid for No. 2 fuel oil in the region in which the facility is located. The Commission is authorized, however, under certain circumstances, to reduce the ceiling to a level not lower than the price of No. 6 fuel oil.

Sec. 204 Method of Passthrough

* * * * *

(e) Determination of Alternative Fuel Cost.—

(1) In General.—Except as provided in paragraph (2), the appropriate alternative fuel cost for any region (as designated by the Commission) shall be the price, per million Btu's, for Number 2 fuel oil determined by the Commission to be paid in such region by industrial users of such fuel.

(2) Reduction of Appropriate Alternative Fuel Cost Allowed.—The Commission may, by rule or order, reduce the appropriate alternative fuel cost—

(A) for any category of incrementally priced industrial facilities, subject to the rule required under section 201 (including any amendment under section 202 to such rule) located within any region and served by the same interstate pipeline; or

(B) for any specific incrementally priced industrial facility which is subject to such requirements and which is located in any region;

to an amount not lower than the price, per million Btu's for Number 6 fuel oil determined by the Commission to be paid in such region by industrial users of such fuel, if and to the extent the Commission determines, after an opportunity for written and oral presentation of views, data, and arguments, that such reduction is necessary to prevent increases in the rates and charges to residential, small commercial, and other high-priority users of natural gas which would result from a reallocation of costs caused by the conversion of such industrial facility or facilities from natural gas to other fuels, which conversion is likely to occur if the level of the appropriate alternative fuel cost were not so reduced.

The legislation provides, in sum, that, if keeping the incremental pricing ceiling at the level of No. 2 fuel oil would be likely to result in fuel switching and a shifting of capital costs so as to increase residential and commercial rates, the Commission may act under authority of subsection 204(e) to reduce the ceiling as necessary, but not lower than the price of No. 6 fuel oil, to prevent incremental pricing from having such a detrimental effect. Although the Commission is authorized to reduce the ceiling so as to minimize the likelihood of fuel switching and its adverse consequences, the Commission believes that subsection 204(e) implies that Congress did not intend that the ceiling be reduced below a point where residential and commercial rates would be higher than they would have been with a No. 2 ceiling.

II. The Commission's Three-Tier Rule

In the Final Rule issued today in this docket, the Commission found that the record shows that a ceiling set at the price of No. 2 fuel oil would result in substantial industrial load loss, though precise quantification is impossible.

On the other hand, it is not clear that high priority consumers would be benefitted by having a single ceiling set at the No. 6 rather than the No. 2 level. Despite some data and arguments that would support a single No. 6 ceiling, an analysis by the Department of Energy and other information seems to indicate that, in some cases, a balancing of induced load losses with the amount of the surcharge passed through to industrial consumers favors a No. 2 ceiling relative to a No. 6 ceiling.

Put differently, the record is clear that in order to carry out the Congressional intent to protect the interests of high priority consumers from *likely* adverse impacts, the Commission must exercise its statutory authority to choose an incremental pricing ceiling other than the price of No. 2 fuel oil. There is, however, a high degree of quantitative uncertainty about the impacts of a ceiling set at the price of No. 6 fuel oil.

In response to this uncertainty, the Commission has developed a system of multiple ceilings. The objective of this system is to maximize recovery of incremental costs from each incrementally priced industrial facility, and at the same time minimize the likelihood that any such facility would switch to an alternative fuel. To this end, the Commission has provided in the Final Rule issued in this docket that three ceilings be established for each region of the country—one at the level of No. 2 fuel oil, another at the level of low sulfur No. 6 fuel oil, and a third at the level of high sulfur No. 6 fuel oil.

An incrementally priced industrial facility would pay a price for natural gas which would include a surcharge determined by the level of the lowest priced type of fuel oil it had the installed capability and the legal authority to use.

A three-tier approach would avoid the establishment of a blanket ceiling for all users. Such a ceiling might be too high for some, resulting in their loss to the system. At the same time, a single ceiling might be too low for others, allowing them to escape some of the costs that Congress intended them to bear under the incremental pricing program. By differentiating among incrementally priced facilities on the basis of fuel burning capability and lawful authority, the three-tier approach would maximize the flow-through of incremental costs to industrial gas customers.

Despite the theoretical attractiveness of the three-tier system, however, and despite the Commission's view that it best meets the statutory mandate contained in Title II, the Commission is concerned about the public interest implications of implementing this system immediately. The major concern stems from the possibility that the three-tier system will lead to significant amounts of investment to install equipment to burn high sulfur No. 6 fuel oil.

III. The Induced Investment Issue

The record in this docket contains considerable discussion and some quantitative data about the amount of investment that would be likely to result as a consequence of the three-tier system. As the record shows, many facilities that could install No. 6 fuel burning capability have not done so in the past because gas has generally been available and curtailment periods have been short. Such firms find it economic and convenient to use No. 2 rather than No. 6 fuel oil as a substitute for gas during their short periods of curtailment. However, if gas for such firms were priced at the No. 2 oil ceiling, these same facilities would find it economically advantageous to install No. 6 capability. As the Department of Energy (DOE) noted:

> Firms * * * may find a residual backup system very attractive economically. While, before, the backup system was being utilized only a small percent of the year, now the backup system is reaping lower fuel prices year round.

There are a number of elements that distinguish a residual oil burning boiler from a distillate oil burning boiler.[2] In order to render a gas-fired boiler physically capable of burning residual oil, the minimum investment a firm would have to make would involve modifying the burners, adding a steam or mechanical atomizer, and adding an insulated storage tank.[3] DOE estimated that an industrial facility could install residual oil firing capability with a minimum investiment of $50,000 to $90,000, depending on what modifications were made to the fuel handling system.[4] Southern California Gas Company, on the other hand, estimated the cost at a relatively modest $29,500 to $65,000 for a 500 horsepower boiler. Although there is some uncertainty about the cost, there is no evidence that the required investment would be large.

Expressed in terms of the cost per MMBtu, the relatively small investment in No. 6 oil burning equipment is very attractive when compared with the savings that would be enjoyed if an end-user thereby became legally able to purchase gas at the price of No. 6 fuel oil. DOE put the cost of installing residual oil capability at 16 to 39 cents per MMBtu, depending on the boiler firing rate. DOE also estimated that the savings in lower gas prices would be between 60 cents (if the end-user qualified for a No. 6 low sulfur ceiling) and $1.20 (if the end-user qualified for a high sulfur No. 6 ceiling.)

Many participants in this proceeding provided specific illustrations of the economic desirability of installing No. 6 capability. For example, the National Aeronautics and Space Administration (NASA) said: "Installation of that capability would be cost-effective for at least three NASA field installations and would represent a 40 percent dollar savings over the total anticipated surcharges." Southern California Gas Company and the American Gas Association (AGA) estimated that the capital costs of installing No. 6 capability would usually be fully recovered within a year's time.[5]

Chairman Katherine E. Sasseville of the Minnesota Public Service Commission stated that the price of No. 2 fule oil in Minnesota typically exceeded the price of No. 6 by more than $1.00 per MMBtu. Under the three-tier approach the user of 300 MMBtu of natural gas a day who has No. 2 alternative fuel capability would be charged at least $300 a day more for natural gas than if he qualified for a high sulfur No. 6 ceiling. If he burned gas 300 days a year, in one year he would pay $90,000 more for his gas. The present value of that yearly cost over 20 years discounted at 10 percent exceeds $750,000. Thus, Chairman Sasseville concluded that such a Minnesota customer would find it cost effective to install the capability to burn No. 6 if that could be done for $750,000 or less. And the record shows it could be. Using the DOE estimate of $90,000 as the cost to install No. 6 capability, Chairman Sasseville's figures imply that the investment could be recovered in one year, even ignoring the tax savings generated by the new investment.

Given the economics that could be realized under a three-tier approach as a consequence of installing the capability to burn No. 6 fuel oil, the record is clear that many firms that currently use No. 2 fuel oil as backup would switch to No. 6. Nationally, however, the precise number that would be able to convert, taking into account economics, environmental laws, and other pertinent considerations, remains unclear at this time despite the efforts of the Commission and participants in this proceeding to provide data for the record.

The present record on precisely how many facilities would be induced to invest in No. 6 capability consists mainly of system-specific examples. To illustrate, DOE provided a study of Wisconsin Gas Company's industrial gas users that may be incrementally priced. The study indicated that there are a significant number of gas boilers in Wisconsin for which distillate oil is used as a backup. Currently, 49 percent of the gas sold to incrementally priced facilities in Wisconsin is consumed at facilities for which No. 2 oil is the alternative fuel. This accounts for 12.4 Bcf of annual consumption. DOE concluded that the users of 8.7 Bcf (70 percent) would install residual fuel backup capability in order to qualify for lower gas prices.

DOE estimated that in the Wisconsin Gas Company service area alone, the total capital investment required for equipment to convert from distillate to residual oil backup capability would be $19.6 million. As for the total nationwide cost of these conversions to No. 6 capability, DOE said that, as an upper bound estimate, between $300 and $400 million would be expended.[6]

In short, the potential for conversions from a No. 2 fuel oil backup capability to a No. 6 capability would be widespread, and, though individual firms could recover the cost relatively quickly, the aggregate national cost could be large. The issue is whether there would be any benefits associated with this national expenditure. It can be argued that there may be an offsetting public benefit in having facilities with the option to burn residual fuel oil as well as natural gas and distillate at a time when there is always a possibility of any one of a variety of unanticipated fuel crises occurring.

There is further concern. As discussed at length in the preamble to the companion three-tier rule in this docket, the record shows that a substantial portion of industrial boiler fuel load already has the capability to burn No. 6 fuel oil. If, in response to the three-tier ceiling, there is widespread conversion from No. 2 to No. 6 backup capability, the remaining amount of industrial boiler fuel load which would be eligible to be incrementally priced at the No. 2 level could be reduced to a *de minimis* amount. In such a situation, the surcharge absorption capability captured by having the three-tier approach rather than a single No. 6 ceiling would be sharply reduced. The reduction could be significant enough that the benefits of a three-tier approach to residential and commerical customers would not be substantially greater then they would be if there were a single No. 6 high sulfur ceiling. This possibility raises a troublesome question about the need for the regulatory and data-support

[2] For example, in order to burn oil grades heavier than No. 2 or No. 4, steam or electric heaters are necessary to raise the temperature, and heavier fuel pumps are needed to transport the fuel. Due to the burning and contamination characteristics of residual oil, high quality refractory brick is required in residual oil burners. (If residual oil were fired in a distillate boiler, severe deterioration of the refractory wall would take place.) In addition, soot blowers are needed to dislodge ash accumulation, and heat exchanging tubes must be replaced if a boiler is retrofitted to have a No. 6 fuel oil firing capability. A steam/air or mechanical atomizer is also needed, as is increased air blower capacity.

[3] Other items such as installation of a sootblower, refractory upgrade, or tube modification are necessary only if No. 6 oil is to be burned for a prolonged period.

[4] In order to have the capability to burn residual oil for a prolonged period of time (e.g., over a week) without excess furnace wear would require an additional $154,000, DOE estimated. Stringent environmental controls would require a much greater investment.

[5] The Southern California Gas Company assumed a $1.00 difference between the price of No. 2 fuel oil and the price of low sulfur No. 6. At the time Southern California Gas filed in this docket, it said the cost of No. 2 fuel oil in California was $4.30 / MMBtu and the cost of low sulfur No. 6 oil (0.5 percent sulfur content) was $3.30/MMBtu.

[6] DOE points out that even if the investment in No. 6 capability were justified at a later date due to increasing supply interruptions, there is a cost of installing the capacity earlier than necessary. DOE estimated that the annual penalty for installing residual oil burning capability earlier than it would otherwise be installed could range from $50–$72 million.

system required to implement the three-tier approach.

IV. Administrative, Data, and Enforcement Considerations

In any cost-benefit analysis relating to the three-tier system, one factor that must be considered is that such a system requires more complex regulations, a more extensive enforcement program and a more complicated data gathering and analysis effort than would be required for a system with a single ceiling.

Under the Final Rule in this docket which implements the three-tier system, there is a certification procedure for determining the alternative fuel capability of incrementally priced industrial facilities. Certification must be made through the filing of an "alternative fuel capability affidavit" signed under oath and filed with the Commission if a facility is equipped to burn No. 5 or No. 6 oil and desires to be incrementally priced accordingly.

This in turn gives rise to an enforcement burden in that the Commission intends to audit a sample of certifications of alternative fuel capability to ensure compliance with the terms of its regulations and the NGPA.

Both the pressure on firms to file alternative fuel capability affidavits and the attendant administrative and enforcement burden would be relaxed for approximately 10 months under the exemption adopted herein. This will allow time for a further assessment of whether the benefits derived from a three-tier approach will, in the end analysis, be worth the administrative and other burdens involved.

As for data collection, the three-tier system poses a challenging assignment to DOE's Energy Information Agency (EIA). EIA has encountered some difficulties in carrying out its assignment to have in place three accurate price ceilings for each of a number of regions.

It is imperative that EIA have the first round of ceilings determined and published by December 20, 1979. Further, it is imperative that those established ceilings have an acceptably high degree of accuracy. Inaccuracy could engender load loss and a burdensome shifting of capital costs to residential and commercial customers. Moreover, the shifted load would place a demand on fuel oil markets this winter that could have undesirable consequences.

EIA's task would be greatly eased and the likelihood of statistically valid results greatly improved if, at the outset of the incremental pricing program, it were required to generate only one ceiling per region instead of the three that would be required under the three-tier approach. Abeyance of the first two tiers until November 1, 1980, would resolve any uncertainty about the ability of EIA to implement the ceiling system and assure that the ceiling system can be administered in an effective way.

V. Environmental Effects

The Environmental Protection Agency (EPA) strongly argued against the three-tier system and for a single No. 6 ceiling. It reasoned that a three-tier approach would cause industries to move from "non-attainment" areas where they are legally limited to using low sulfur No. 6 fuel oil to "attainment" areas where they would be permitted to use high sulfur No. 6 fuel oil.

The basic incentives for industry to relocate in attainment areas are the result of the 1977 Clean Air Act Amendments. The three-tier approach would only have an inconsequential impact in comparison. The Commission doubts any firms could decide to incur the capital cost associated with relocating just to get the benefit of being legally permitted to use fuel oil with a higher sulfur content and, thus, to get a lower gas price. The same benefit could obviously be gotten for a far lower price by installing emission control equipment.

EPA further argues that a three-tier rather than single-tier ceiling could reduce the incentive for industries to make the environmentally advantageous move from oil to gas. The Commission believes that the economic incentive to use gas would remain even with the three-tier system. However, the proposed period of exemption would provide an opportunity to evaluate further the environmental implications of the three-tier approach with the benefit of having the incremental pricing program actually in place.

VI. Conclusion

After evaluating the considerations discussed above, it is the Commission's conclusion that the public interest would be served by implementing the No. 6 high sulfur ceiling for all non-exempt natural gas consumers at this time and postponing implementation of the upper two ceilings until November 1, 1980.

This period of abeyance would permit all concerned to become familiar with the working of the incremental pricing program in practice as well as theory. The number and characteristics of the incrementally priced facilities will become clearer, and the price relationships among the various alternative fuels will be better understood. Thus, the ability to analyze and evaluate the amount of induced investment in No. 6 oil burning capability and its implications for the economic interests of the high priority gas consumers as well as consumers of fuel oil will be much improved by a period of upper tier abeyance. Additionally, implementation of an effective incremental pricing program would be eased if, during the first few months of the program, there were a single price ceiling rather than three ceilings.

Even beyond these public policy implications are broader energy policy implications in the choice between a single No. 6 ceiling and the three-tier system. These were articulated by the then Secretary of Energy, James R. Schlesinger, when DOE filed comments which were accompanied by a study in this proceeding. Secretary Schlesinger expressed the Department of Energy's view that it is in the national interest for natural gas to displace imported oil. Foreign oil is the marginal source of energy, and any fuel oil that is consumed instead of natural gas comes from the foreign barrel. Additionally, the Secretary observed that the nation's energy resources should be efficiently used. He noted that the total of the wellhead cost of natural gas plus variable delivery costs is currently below the cost of all alternate petroleum fuels on a national basis and is likely to remain so for some time. Thus, natural gas should be used to displace more costly petroleum. Based on these considerations, Secretary Schlesinger stated that the Department's preference would be to have the ceiling on incremental pricing set at the level of high sulfur No. 6 fuel oil.

Secretary Schlesinger went on to say, however, that, in the Department's view, if adoption of a uniform No. 6 ceiling decreased the surcharge absorption capability of incrementally priced facilities so must that, in at least some cases, the reduction from the No. 2 price level would offset the benefit to the high priority customer of avoiding load loss, then, under subsection 204(e) of the NGPA, the ceiling should not be reduced to a uniform No. 6 level.

The Commission agrees that the section 204 test is rather specific and it would not be appropriate for the Commission to base a decision on the several wider public policy concerns that are presented to it in this proceeding. Yet, the Commission believes that is must be cognizant of such concerns. Moreover, it is conscious that section 206 of the NGPA provides a mechanism for it to bring these public policy implications before the Congress. Hence, the Commission is promulgating this temporary exemption rule and transmitting it to Congress for review.

These regulations are prescribed as final regulations without further opportunity for comment because they rest upon the record already developed in this docket. In the Notice of Proposed Rulemaking in this docket, parties were invited to address not only the three-tier ceiling, but to address other approaches including, specifically, a one-tier ceiling established at the No. 6 level. Hearings were held in four cities across the nation, and over 50 written comments were received. To have further hearings at this time on the issue of whether there should be a three-tier or single-tier No. 6 ceiling until Novermber 1, 1980 would result in the replication of an already developed and ample record.

(The Natural Gas Policy Act of 1978, Pub. L. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, if neither House of Congress passes a Resolution of Disapproval of the regulation transmitted to it in this order, Title 18 of the Code of Federal Regulations is amended in Part 282 to read as set forth below, effective December 1, 1979.

By the Commisssion.

Lois D. Cashell,

Acting Secretary.

1. Section 282.402 is amended by adding a new paragraph (c) to read as follows:

§ 282.402 General rule.

* * * * *

(c) *Exemption.* For any month during the period January 1, 1980 through October 31, 1980, the alternative fuel price ceiling which shall be applicable to a non-exempt industrial boiler fuel facility for incremental pricing purposes shall be the ceiling which has been published for No. 6 high sulfur fuel oil for that month in accordance with § 282.404 for the incremental pricing region in which the facility is located. Publication of ceilings for No. 2 fuel oil and No. 6 low sulfur fuel oil for such period may be omitted.

[FR Doc. 79-30758 Filed 10-3-79; 8:45 am]
BILLING CODE 6450-01-M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 282

[Docket No. RM79-48]

Section 206(d) Exemption for New Small Boiler Facilities From the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978; Proposed Rulemaking and Public Hearing

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking and Public Hearing.

SUMMARY: The Federal Energy Regulatory Commission hereby proposes to promulgate a rule to enlarge the class of small boiler facilities that are exempt from the incremental pricing program under Title II of the Natural Gas Policy Act of 1978 (NGPA). This proposed rule would be adopted under the authority of section 206(d) of the NGPA, and would grant an exemption from the incremental pricing program to those industrial boiler fuel facilites which came into existence after November 9, 1978, or which come into existence at some time in the future, and which have a total capacity of 300 thousand cubic feet (Mcf) per day or less.

DATES:

Comments by October 29, 1979.
Requests to speak by October 15, 1979.
Hearing date: October 22, 1979.

ADDRESS: All comments and requests to speak to: Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washingotn, D.C. 20426 (Reference Docket No. RM79-48). Hearing location: Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8033.

Issued September 28, 1979.

I. Background

Title II of the Natural Gas Policy Act of 1978 (NGPA) (Pub. L. No. 95-621) requires that interstate pipelines and local distributon companies pass through certain portions of their natural gas acquisition costs to industrial users in the form of surcharges. These surcharges may not, however, raise the price of gas to the user above the price of fuel oil which could be used as an alternative to natural gas.

The incremental pricing program is to be implemented in two phases. The only faciltities affected during the first phase will be those large industrial facilities using natural gas as fuel for boilers. Title II requires that the regulations implementing this first phase be promulgated by November 9, 1979.[1]

During the second phase of the program, incremental pricing may be extended to a broader class of industrial users than those affected by the first stage. The NGPA sets May 9, 1980, as the date for the regulations implementing the second phase and establishes that those regulations will be subject to Congressional review and possible disapproval by either House.

Subsections 206 (a), (b), and (c) of the NGPA provide that small industrial boiler fuel facilities in existence on November 9, 1978, agricultural users, schools, hospitals, and certain other facilities shall be exempt from incremental pricing. In addition, to the extent provided by the Commission by rule, the use of natural gas as a boiler fuel by any qualifying cogeneration facility (which meets the requirements prescribed by the Commission pursuant to section 201 of the Public Utility Regulatory Policies Act of 1978) shall be exempt from incremental pricing.

Subsection 206(a) of the NGPA requires the Commission to grant an interim exemption from incremental pricing to any industrial boiler fuel facility which was in existence on November 9, 1978, and which used no more than an average of 300 Mcf per day for any month in a base period determined appropriate by the Commission. The Commission, in the regulations relating to this interim exemption in Docket No. RM79-14, has adopted 1977 as the base period. Section 206 also sets May 9, 1980, as the date for the permanent rule which will contain certain statutorily prescribed refinements of the interim rule.

Under subsection 206(d) of the NGPA, the Commission may, by rule or order, exempt other individual industrial facilities or categories of such facilities from the incremental pricing program. Rules proposing such exemptions must be submitted to the Congress for its review prior to taking effect.

In the Notice of Proposed Rulemaking in Docket No. RM79-14, issued on June 5, 1979 (44 FR 33099, June 8, 1979), the Commission announced that it would issue a Notice of Proposed Rulemaking in Docket No. RM79-48 regarding a new small boiler exemption under subsection 206(d) of the NGPA for "new" small boilers—i.e., small boilers constructed since November 9, 1978. This was discussed at page 12 of the June 5th Notice (pp. 33100-33101 in the Federal Register). This Notice of Proposed Rulemaking and Public Hearing is the one referred to in the June 5th Notice.

The regulations in this docket would exempt from incremental pricing the gas used to small boiler facilities which came into existence after November 9, 1978, including those which come into existence at some time in the future. These facilities would be referred to as "new" facilities.

By its terms, the NGPA grants an exemption only to those "small" boiler facilties which were in existence on November 9, 1978, the date of enactment ("existing" facilities). Both the statute and the legislative history are silent as to the reason why an exemption from the incremental pricing program was granted only to existing small boiler facilities and not to new small boiler facilities. The Commission believes that, for purposes of implementing the incremental pricing program, it would be inconsistent and inequitable to distinguish between small facilities which were in existence on November 9, 1978 and those which came into existence after November 9, 1978. Therefore, the Commission proposes to enlarge the class of exempt small boiler facilities to include new small boiler facilities.

Since the regulations below are being proposed pursuant to subsection 206(d) of the NGPA, if they are adopted by the Commission as a final rule, they will be submitted to the Congress for review prior to taking effect. After the regulations are submitted to each House of Congress, they may take effect following 30 days of continuous session of Congress (as set forth in subsection 507(b) of the NGPA) unless either House adopts a resolution of disapproval within that 30 day period.

II. Discussion

A. Regulations Proposed

The effect of the proposed rule below, if adopted as a final rule, would be to enlarge the class of small boiler facilities which are exempt from the incremental pricing program. For this reason, the Commission proposes to use 300 thousand cubic feet (Mcf) as the threshold for determining "small", which is the same threshold required by section 206(a)(1) for the interim statutory exemption for existing small boiler

[1] These regulations are contained in two dockets, Docket Nos. RM79-14 and RM79-21.

facilities. Thus, a new facility which has a total capacity of 300 Mcf per day or less would be eligible for an exemption from the incremental pricing program.

Furthermore, the proposed regulations contain a provision which would require that, in the event the 300 Mcf threshold is lowered when the permanent exemption for existing small boilers becomes effective, the threshold for the exemption for new small boiler facilities proposed in this docket would also be lowered.

Section 206(a)(2) of the NGPA requires that, in the permanent exemption for existing small boiler facilities, the Commission shall lower the 300 Mcf threshold if necessary to assure that the use of natural gas in 1977 by exempt existing small industrial boiler fuel facilities did not exceed 5 percent of the total volume of natural gas that was transported in interstate pipelines and used as a boiler fuel in 1977.

B. Method for Determining Size of a Boiler Facility.

The most significant question that must be addressed in proposing to enlarge the class of small boiler facilities eligible for exemption from the incremental pricing program is how to determine the size of such facilities. The statutory exemption for existing small boiler facilities is calculated on a base period usage approach.

In determining how to evaluate the size of a boiler facility, no method is free of difficulties. The most obvious approach would be the use of some reference period for measuring actual gas consumption. However, under any such "base period" approach, the selection of an appropriate base period is an immediate problem. Since, by definition, a new facility would be one which has come into existence since November 9, 1978, the class of boilers which would have a full year during which gas consumption could be measured would be very small. Use of less than a full year as a base period might result in distortions due to the seasonal availability of gas on many systems and seasonal patterns of usage.

Use of a fixed based period would also be inadequate for determining the status of facilities coming into existence during the base period or at some point in the future. On the other hand, if the problem were addressed through use of a "rolling" base period, the owner of a new facility would not be able to ascertain the status of the facility until after some interval of time had elapsed.

A fixed based period approach could also provide an incentive to circumvent the intent of the new small boiler exemption. One manner of circumvention we foresee would be to hold the gas consumption of a larger than 300 Mcf facility at or below 300 Mcf per day for the duration of the reference period. Only a burdensome system of continuous monitoring would suffice to close this loophole.

Moreover, any base period approach, no matter how carefully constructed and monitored, could be circumvented to some degree. A large new boiler facility could find it economically attractive to burn exactly 300 Mcf of gas per day and satisfy the remaining fuel requirements with oil. Thus, a perverse fuel use pattern would result from the base period regulation. Economic waste would be highly likely.

The alternative to one of the base period approaches which the Commission believes has the greatest probability of success is to determine the size of a boiler facility by looking to its capacity. One problem with this approach, however, is developing a rule for relating boiler capacity to fuel use. A small boiler which operates around the clock may consume more gas than a larger boiler which operates intermittently.

Since a boiler's firing rate (nameplate rating) is stated in terms of MMBtu (million British thermal units) per hour or Mcf per hour, we have determined to make some assumptions about the fraction of rated capacity actually utilized and the number of hours a boiler is fired per day. The first assumption would appear to be best met by assuming that a boiler is operated at rated capacity. Although some boilers could be operated at a rate above or below the nameplate rating, the Commission believes that nameplate rating is the most objective, verifiable, administratively feasible standard to use in determining a boiler's capability.

The second assumption, regarding the number of operating hours per day, is more problematic. A three shift per day operation would be a conservative assumption in that no facilities so evaluated and fund exempt by reason of small size could in fact be using more than 300 Mcf per day (except by exceeding the rated capacity of the boiler). Since not all boilers are run for three shifts every day, the "24 hour per day" assumption might result in many boiler facilities which actually consume much less than 300 Mcf per day being subject to the incremental pricing program.

Furthermore, to assume a one shift per day operation would probably also be inappropriate. Generally, it is considered inefficient to run a boiler for only 8 hours per day. The Commission therefore proposes a 16 hour period as a reasonable middle ground for determining a boiler's capacity. In effect, this approach assumes dual shift operation.

For boilers whose nameplate rating is stated in terms of Mcf per hour, we propose to multiply the rating by 16 hours per day in order to calculate the boiler's capacity. For boilers rated in terms of MMBtu per hour, we propose to convert the rating to Mcf per hour (based on a conversion factor of one MMBtu to one Mcf) before multiplication by 16.

For a facility with multiple boilers, the total capacity of the facility would be the sum of the capacities of all boilers within the facility which have the capability to burn natural gas. Any new facility with a total capacity which is the lesser of: (1) no more than 300 Mcf per day; or (2) no more than such other volume of natural gas determined by the Commission in accordance with section 206(a)(2)(B)(ii) of the NGPA would be eligible for an exemption from the incremental pricing program.

C. Obtaining the Exemption. We are proposing that a facility would obtain an exemption by filing an affidavit. The exemption would be effective until such time as the facility modified any of its boilers if the modification resulted in a change in a boiler's capacity, or until the facility was expanded by the addition of one or more boilers with gas fired capability. At such a time, the facility would be required to notify the Commission and its natural gas supplier of these changes, and the facility's continued eligibility for an exemption from the incremental pricing program would be determined. A copy of the Affidavit we propose to utilize is attached hereto.

III. Summary of The Proposed Rule

The proposed regulation would add new §§ 282.210 and 282.211 for new small boiler exemptions to Part 282 of the Commission's regulations.

The new § 282.210 would exempt small boiler facilities which came into existence after November 9, 1978, or which come into existence at some time in the future. For a facility which has more than one boiler with gas fired capability, the facility's total capacity would be the sum of the capacities for each boiler which has the capability to burn natural gas. The size of a facility would be determined by adding the nameplate rated capacity for all boilers within a facility which have the capability to use natural gas. For a boiler rated in terms of Mcf per hour, the boiler's capacity would be obtained by multiplying the rating by 16. If a boiler is rated in terms of MMBtu per hour, before being multiplied by 16, the rating would first be converted to Mcf per hour using a conversion factor of one Mcf per one MMBtu.

Any facility with a rated capacity of no more than 300 Mcf per day would be granted an exemption from the incremental pricing program. The 300 Mcf figure would be used until such time as the permanent exemption for existing small boiler facilities becomes effective. At that time, the number that would be used as the threshold for the permanent exemption would also be used for determining exemptions for new small boiler facilities under § 282.210 of the regulations.

The new § 282.211 would describe the procedures that must be followed in order to obtain a new small boiler exemption. Suppliers would be obligated to notify the facilities which might be exempt and to mail affidavits for new small boiler facility exemptions to those facilities which request them. The other requirements for filing and processing affidavits adopted in Docket No. RM79-14 would be used for the exemptions proposed in this rule.

The affidavit that would be filed in order to obtain an exemption would contain one question, which, if answered affirmatively, would result in an exemption for new small boiler facilities.

IV. Comments Requested

The Commission requests comments on all aspects of the proposed regulations set forth below. The Commission particularly invites comments on the issues identified above and on approaches to those issues other than the ones reflected in the regulations below.

In addition, the Commission is concerned that, if this proposal is adopted as a final rule, it may provide an incentive for the construction of small boiler facilities instead of the expansion of existing facilities. Or, the rule might provide an incentive for the addition of non-gas burning boilers to increase the facility's capability. Comments are, therefore, requested on these potential problems. Comments are especially requested on the economic feasibility of: (1) expanding a facility by the addition of non-gas burning boilers in order for the facility to retain its exemption; or (2) modifying a facility by reducing its total capacity to burn natural gas as a boiler fuel in order to gain an exemption from the incremental pricing program.

V. Comment Procedures

A. *Written Comments.* Interested persons are invited to submit written comments, data, views, or arguments with respect to this proposal. Comments should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should reference Docket No. RM79-48. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST, October 29, 1979, will be considered by the Commission prior to promulgation of final regulations. All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426, during regular business hours.

B. *Public Hearing.* A public hearing on this proposed rule will be held on October 22, 1979, beginning at 10: a.m. E.D.T. at the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426. The exact location will be posted at the Commission on the morning of the hearing. Interested persons may also obtain this information by calling the Office of the Secretary of the Commission.

Requests to participate in the hearing should be directed to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, no later than seven days prior to the hearing. Requests should reference Docket No. RM79-48, and should indicate the amount of time required for the oral presentation, and the telephone number at which the person making the presentation can be reached. Persons participating in the public hearing should, if possible, bring 50 copies of their testimony to the hearing. A list of the participants in the hearing will be available in the Commission's Office of Public Information three days before the hearing and will be available at the site of the hearing on the morning it is convened.

The hearing will not be of a judicial or evidentiary type. There will be no cross-examination of persons presenting statements. However, the panel may question such persons and any interested person may submit questions to the presiding officer to be asked of persons making statements. The presiding officer will determine whether the question is relevant and whether the time limitations permit it to be presented. Any further procedural rules will be announced by the presiding officer at the hearing. Transcripts of the hearing will be available in the public file for this proceeding, Docket No. RM78-48, in the Commission's Office of Public Information,

(Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350, 15 U.S.C. 3301, *et seq.*)

In consideration of the foregoing, the Commission proposes to amend Part 282 of Subchapter I, Chapter 1, Title 18, Code of Federal Regulations, as set forth below.

By Direction of the Commission.

Lois B. Cashell,

Acting Secretary.

1. Part 282 is amended by adding new §§ 282.210 and 282.211 to read as follows:

§ 282.210 Exemptions for new small boilers under section 206(d).

(a) *General Rule.* Natural gas used for boiler fuel in a new small industrial boiler fuel facility shall be exempt from incremental pricing under this part.

(b) *Definition.* For purposes of this section, a "new small industrial boiler fuel facility" is a facility which:

(1) came into existence after November 9, 1978; and

(2) has total capacity, as determined in accordance with paragraph (c) of this section, which is no more than the lesser of: (i) 300 Mcf; or (ii) the volume of natural gas determined by the Commission in accordance with section 206(a)(2)(B)(ii) of the NGPA.

(c) *Capacity.* (1) *Definition.* The capacity of a boiler which has the capability to burn natural gas is the volume of natural gas, stated in Mcf, which would be consumed if the boiler were operated at nameplate rated capacity for a continuous 16 hour period.

(2) *Rating in terms of MMBtu.* For purposes of this section, the capacity of a boiler whose nameplate rated capacity is stated in terms of MMBtu per hour shall be obtained by converting the MMBtu rating to an Mcf equivalent. This conversion shall be based on a conversion factor of one MMBtu to one Mcf.

(3) *Total Capacity of a facility.* The total capacity of an industrial boiler fuel facility shall be the sum of the capacities of all boilers within the facility which have the capability to burn natural gas.

§ 282.211 Obtaining an exemption for a new small boiler facility.

(a) *General.* This section establishes procedures by which owners or operators of new small industrial boiler fuel facilities may obtain an exemption for natural gas used in such facilities.

(b) *Exemption by affidavit.* (1) *Commission to provide exemption affidavits.* As of (the effective date of this section), new small boiler exemption affidavits as described in paragraph (b)(3) of this section will be available to natural gas suppliers for purposes of paragraph (b)(2) of this section and to any other interested person upon request from the Office of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(2) *Availability of exemption affidavits from natural gas suppliers.* (i) Natural gas suppliers shall notify facilities which may be eligible for an exemption under § 282.210 and shall mail a new small boiler exemption affidavit to those facilities which request one.

(ii) Natural gas suppliers shall make new small boiler exemption affidavits available at their principal place of business on an ongoing basis during regular business hours.

(3) *Contents of exemption affidavit.* The new small boiler exemption affidavit will provide the owner or operator of an industrial boiler fuel facility with an opportunity to respond to the following question: Did your facility come into existence after November 9, 1978, and does the facility, on the basis of records, documents, or data in the customer's posssesion, have a total capacity which is no more than 300 Mcf per day?

Appendix A

Note.—This appendix will not appear in the Code of Federal Regulations.

Federal Energy Regulatory Commission, Washington, D.C.

Exemption From Incremental Pricing for the Use of Natural Gas in New Small Boiler Fuel Facilities

Docket No. RM79-48

Participation is Voluntary. Copies of executed exemption affidavits filed with the Commission shall be available through the Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.

Please Read Before Completing This Affidavit

Purpose

The Natural Gas Policy Act of 1978 (NGPA) provides that natural gas used as boiler fuel by any industrial boiler fuel facility will be subject to incremental pricing surcharges unless exempted. The statute provides for certain exemptions from these incremental pricing surcharges. The affidavit entitled "Exemptions From Incremental Pricing for Certain Categories of Industrial Boiler Fuel Use of Natural Gas" serves the purpose of identifying those uses of natural gas that are entitled to a full or partial statutory exemption.

In addition, the statute provides that the Federal Energy Regulatory Commission has the discretion to propose other exemptions from the incremental pricing program. The Commission has issued a rule which provides that new small industrial boiler fuel facilities which have come into existence since November 9, 1978, are eligible for an exemption from incremental pricing. This affidavit serves the purpose of identifying those "new" small boiler facilities which are entitled to an exemption from incremental pricing surcharges.

Notice

If you do not complete and return this affidavit or the affidavit entitled "Exemptions From Incremental Pricing for Certain Categories of Industrial Boiler Fuel Use of Natural Gas," setting forth your claim to an exemption *ALL* gas sold to your facility will be subject to incremental pricing surcharges. Additionally, if circumstances or ownership change, you should immediately notify your natural gas supplier(s) of the change so that the correct amount of surcharge may be calculated as to your gas use or, if needed, you may complete a new exemption affidavit to obtain a new or changed exemption from the incremental pricing surcharges. Failure to report changes can subject your facility to civil penalties of appropriate amounts under Section 504 of the Natural Gas Policy Act of 1978.

General Instructions

If you claim an exemption from incremental pricing surcharges for the gas used by your facility which has been identified by your natural gas supplier as a potentially non-exempt industrial boiler fuel facility, this affidavit should be completed and signed, under oath, by a responsible official associated with the facility. A separate affidavit must be filed for each facility for which an exemption from incremental pricing surcharges is claimed.

The original and five copies of this affidavit should be submitted to: Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

Also, one copy must be submitted to your natural gas supplier. Additionally, each industrial facility shall retain such records, documents and data which formed the basis for the exemption claimed on this affidavit. Definitions which may be helpful in completing this affidavit are provided below.

If you have any questions concerning this affidavit, contact Ms. Alice Fernandez on (202) 275-4408.

Definitions

(1) "Natural gas supplier" means an interstate pipeline or a local distribution company.

(2) "Local distribution company" means any person other than an interstate pipeline that receives gas directly or indirectly from an interstate pipeline and which is engaged in sale of natural gas for resale or for ultimate consumption. A person is not considered as having received gas directly or indirectly from an interstate pipeline if the only service performed by an interstate pipeline for the purchaser is a transportation service.

(3) "Boiler fuel use" means the use of any fuel for the generation of steam or electricity.

(4) "Facility" means all buildings and equipment located at the same geographic site which are commonly considered to be part of one plant, mill, refinery, or other industrial complex.

(5) "Industrial facility" means any facility engaged primarily in the extraction or processing of raw materials, or in the processing or changing of raw or unfinished materials into another form or product.

(6) "Non-exempt industrial boiler fuel facility" means any industrial boiler fuel facility other than any such facility which has been exempted from the incremental pricing program in accordance with Part 282 of the Commission's rules and regulations.

(7) "Capacity" means, as to a boiler which has the capability to burn natural gas, the volume of natural gas, stated in Mcf, which would be consumed if the boiler were operated at nameplate rated capacity for a continuous 16 hour period. The capacity of a boiler whose nameplate rated capacity is stated in terms of MMBtu per hour shall be obtained by converting the MMBtu rating to an Mcf equivalent. This conversion shall be based on a conversion factor of one MMBtu to one Mcf.

(8) "Total capacity of a facility" is the sum of the capacities of all boilers within an industrial boiler fuel facility which have the capability to burn natural gas.

1.0 Name of Company or Organization: ——

* * * * *

2.0 Name of Facility: ——

* * * * *

3.0 Address: Number —— Street ——

City/Town County State Zip Code

* * * * *

4.0 Name of Natural Gas Supplier: ——

5.0 Did your facility come into existence after November 9, 1978, and does your facility, on the basis of records, documents or data in your possession, have a total capacity, as defined in the "Definitions" of this affidavit, which is no more than 300 Mcf per day?

(a) ☐ Yes . . . Sign and return affidavit

(b) ☐ No . . . Do not return affidavit

Dated: ——

Person completing this affidavit:

Name ——

Title ——

Phone Number ——

Subscribed and sworn to before me this —— day of ——

Notary Public——.

[FR Doc. 79-30759 Filed 10-3-79; 8:45 am]

BILLING CODE 6450-01-M

18 CFR Part 282

[Docket No. RM79-45]

Exemption from Incremental Pricing for Load-Balancing Facilities Which Burn Coal; Intent not to Establish a Rulemaking Proceeding

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Intent not to Establish a Rulemaking Proceeding.

SUMMARY: In the Notcie of Proposed Rulemaking issued in Docket No. RM79-14, *Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978* (June 5, 1979 (44 FR 33099, June 8, 1979)), the Federal Energy Regulatory Commission (Commission) announced the opening of a docket to receive comments on whether a rulemaking proceeding should be established with respect to an exemption from incremental pricing for load-balancing facilities which have the capability to burn coal. Based upon a review of the comments, the Commission has determined not to institute a rulemaking proceeding in this matter. Thus, the Commission hereby gives notice that Docket No. RM79-45 is terminated.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8033.

Issued: September 28, 1979.

I. Background

In the Notice of Proposed Rulemaking issued in Docket No. RM79-14, *Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978* (June 5, 1979 (44 FR 33099, June 8, 1979)), the Federal Energy Regulatory Commission (Commission) announced the opening of a docket to receive comments on whether a rulemaking proceeding should be established with the respect to an exemption from incremental pricing for load-balancing facilities which have the capability to burn coal. Such an exemption was discussed at pp. 11-16 of the June 5th Notice (pp. 33100-33101 in the Federal Register).

On July 3, 1979 a Notice of Opportunity to Comment on Whether a Rulemaking Proceeding Should be Established (44 FR 40898, July 13, 1979) was issued for the purpose of providing further public notice of the announcement which was included in the Docket No. RM79-14 Notice of Proposed Rulemaking. Comments were due no later than August 1, 1979.

Fourteen comments were received in this docket. A list of those commenting is attached to this notice as an Appendix. Based upon a review of these comments and its own analysis, the Commission has determined not to institute a rulemaking proceeding in this matter. Thus, the Commission hereby gives notice that no rulemaking proceeding will be established and Docket No. RM79-45 is terminated.

II. Discussion

Nine of the fourteen comments received in this docket requested the institution of a rulemaking proceeding to exempt from the incremental pricing program all load-balancing facilities which have the capability to burn coal. Five of these comments expressed concern that, if load-balancing facilities which have the capability to burn coal are subject to incremental pricing, there will be a potential for those facilities to shift from the use of gas to the use of coal.

The commenters argued that raising the price of gas to a price, at a minimum, proximate to the price of No. 6 fuel oil would make it economically impractical for load-balancing facilities to continue to burn gas because the price of coal is already much lower than the price of No. 6 fuel oil. If substantial switching were to occur, the result could be higher prices to high priority customers because there would be fewer industrial users to share the fixed costs of operating a pipeline system. The counter-balancing argument to this point is, of course, that an exemption for load-balancing facilities which have the capability to burn coal would quite probably result in higher prices to high priority customers because the costs which could not be passed through by way of incremental pricing surcharges would then be passed on to high priority users.

It has not been established that a substantial amount of load-shifting will occur if facilities with coal-burning capability are subject to incremental pricing. Although the commenters were concerned about the potential for load-shifting, none of the comments attempted to estimate either the number of facilities that may be expected to switch to coal for use as a boiler fuel or the amount of gas sales that would be lost if these load-balancing facilities were not exempt from incremental pricing.

In addition, the characteristics and effects of load-balancing on rate structures vary from system to system. The American Gas Association emphasized that load-balancing is not a concept susceptible to uniform national treatment. It is possible that the benefits of some load-balancing sales may diminish for certain distribution companies if there is no exemption from incremental pricing for such sales. That possiblity, however, does not justify a blanket exemption for all load-balancing facilities which have the capability to burn coal.

The Commission's primary reason for not granting a blanket exemption for load-balancing facilities which have the capability to burn coal is that such an exemption would be contrary to national energy policy. The effect of a blanket exemption for facilities which have the capability to burn coal would be to encourage the consumption of gas instead of coal. Recent legislation such as the Powerplant and Industrial Fuel Use Act reflects the national energy policy to encourage the consumption of coal, which is our most abundant energy resource, in those facilities where coal can be utilized. The Commission believes that is should not take any action which would be inconsistent with or weaken this policy.

Congress has given the Commission, in sections 206(d) and 502(c) of the NGPA, the flexibility to provide relief when necessary. The Commission believes that the regulations which implement these two provisions, 18 CFR 282,206 and 18 CFR 1.41, provide adequate avenues for any party to request administrative relief on a case-by-case basis. An adjustment under § 1.41 in the form of an exception to the incremental pricing regulations in Part 282 may be granted upon a showing by the applicant that relief is necessary to prevent special hardship, inequity or an unfair distribution of burdens. The Commission has the capability to rapidly process a § 1.41 petition for relief and believes it will be able to handle any such petitions in an expeditious and equitable manner.

However, the Commission does not intend that the § 1.41 procedures should provide the vehicle for generalized challenges to Title II of the NGPA and the regulations promulgated thereunder. The § 1.41 procedures have been adopted by the Commission simply to provide an avenue of administrative relief for parties which are uniquely affected by Commission regulations, and not to provide an arena for inquiries into policy questions of broad applicability.

The four comments which opposed the establishment of a rulemaking proceeding in this docket stated reasons generally consistent with those described above for not proceeding any further with a rulemaking to exempt load-balancing facilities which have the capability to burn coal. One comment argued that the Commission should go one step further and encourage conversions to coal in order to free gas supplies for use in boilers where coal is not a feasible alternative.

For the reasons stated in this notice, a rulemaking regarding an exemption from incremental pricing for load-balancing facilities which have the capability to burn coal will not be initiated The Commission hereby gives notice that Docket No. RM79-45 is terminated.

By direction of the Commission.

Lois D. Cashell,
Acting Secretary.

Appendix

Following is a list of those who submitted comments in Docket No. RM79-45:

The American Gas Association
Associated Gas Distributors
The Kennecott Copper Corporation, et al
Mountain Fuel Supply Company
Natural Gas Pipeline Company of Ameria
Potlatch Corporation
The Process Gas Consumers Group, The Georgia Industrial Gas Group, and The American Iron and Steel Institute
Public Service Company of Colorado
Public Service Electric and Gas Company
Republic Steel Corporation
Richard Smyth, Commissioner, Wyoming Public Utilities Commission
State of Wisconsin, Public Service Commission
The United Distribution Companies
Wisconsin Gas Company

[FR Doc. 79-30760 Filed 10-3-79; 8:45 am]

BILLING CODE 6450-01-M

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18 CFR Part 282

[Docket No. RM79-46]

Exemption From Incremental Pricing for Load-Balancing Facilities Which Burn Oil; Intent Not to Establish a Rulemaking Proceeding

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Intent not to Establish a Rulemaking Proceeding.

SUMMARY: In the Notice of Proposed Rulemaking issued in Docket No. RM79-14, *Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978* (June 5, 1979 (44 FR 33099, June 8, 1979)), the Federal Energy Regulatory Commission (Commission) announced the opening of a docket to receive comments on whether a rulemaking proceeding should be established with respect to an exemption from incremental pricing for load-balancing facilities which have the capability to burn oil. Based upon a review of the comments, the Commission has determined not to institute a rulemaking proceeding in this matter. Thus, the Commission hereby gives notice that Docket No. RM79-46 is terminated.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8033.

Issued September 28, 1979.

I. Background

In the Notice of Proposed Rulemaking issued in Docket No. RM79-14, *Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978* (June 5, 1979 (44 FR 33099, June 8, 1979)), the Federal Energy Regulatory Commission (Commission) announced the opening of a docket to receive comments on whether a rulemaking proceeding should be established with respect to an exemption from incremental pricing for load-balancing facilities which have the capability to burn oil. Such an exemption was discussed at pp. 11-16 of the June 5th Notice (pp. 33100-33101 in the Federal Register).

On July 3, 1979, a Notice of Opportunity to comment on whether a Rulemaking Proceeding should be Established (44 FR 40898, July 13, 1979) was issued for the purpose of providing further public notice of the announcement which was included in the Docket No. RM79-14 Notice of Proposed Rulemaking. Comments were due no later than August 1, 1979.

Sixteen comments were received in this docket. A list of those commenting is attached to this notice as an Appendix. Based upon a review of these comments and its own analysis, the Commission has determined not to institute a rulemaking proceeding in this matter. Thus, the Commission hereby gives notice that no rulemaking proceeding will be established and Docket No. RM79-46 is terminated.

II. Discussion

Thirteen of the sixteen comments received in this docket requested the institution of a rulemaking proceeding to exempt from the incremental pricing program all load-balancing facilities which have the capability to burn oil. Nine of these comments expressed concern that, if load-balancing facilities which have the capability to burn oil are subject to incremental pricing, there will be a potential for those facilities to shift from the use of gas to the use of oil.

Many comments pointed out that the price of gas to load-balancing facilities is often lower than to other customers because the service is usually interruptible. These lower prices are what makes the gas service attractive. If the price should be raised—via incremental pricing surcharges—there would be little economic reason for these industrial facilities to use natural gas when it is available. If substantial switching (to oil) were to occur, the result could be higher prices to high priority customers because there would be fewer industrial users to share the fixed costs of operating a pipeline system. This result, the commenters argue, would be contrary to the objectives of Title II of the NGPA.

The facilities affected by the first phase of the incremental pricing program are largely those which have alternate fuel capability. A substantial number of these facilities, the Commission believes, are load-balancing facilities. To grant them an exemption from the incremental pricing program would allow the very users whom Congress intended should bear incremental surcharges to be shielded from the impact of the first phase of the incremental pricing program.

Furthermore, the alternative fuel price ceiling applicable to most of the load-balancing facilities with oil-burning capacity will probably be set at the No. 6 fuel oil price, since it is the Commission's belief that these facilities generally have No. 6 capability. In any event, however, the ceiling price applicable to an incrementally priced facility, determined in accordance with the methodology discussed in the final rule in Docket No. RM79-21 (*Regulations Implementing Alternative Fuel Cost Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978*), will be set low enough that the load-balancing facilities which have the capability to burn oil should not have an economic reason to switch from gas to oil as a result of the incremental pricing program.

Two comments suggested that the applicable alternative fuel price ceiling be lowered by 10 percent for load-balancing facilities which have the capability to burn oil. Again the Commission emphasizes that the methodology set forth in Docket No. RM79-21 for setting the price of No. 6 fuel oil will result in a ceiling price which should be very close to, if not lower than, the price any load-balancing facility with oil-burning capability would pay for oil. Thus, no further adjustments should be needed.

In addition, the characteristics and effects of load-balancing on rate structures vary from system to system. The American Gas Association emphasized in its comments that load-balancing is not a concept susceptible to uniform national treatment. It is possible that the benefits of some load-balancing sales may diminish for certain distribution companies if there is no exemption from incremental pricing for such sales. That possibility, however, does not justify a blanket exemption for all load-balancing facilities which have the capability to burn oil.

Congress has given the Commission, in sections 206(d) and 502(c) of the NGPA, the flexibility to provide relief when necessary. The Commission believes that the regulations which implement these two provisions, 18 CFR 282.206 and 18 CFR 1.41, provide adequate avenues for any party to request administrative relief on a case-by-case basis. An adjustment under § 1.41 in the form of an exception to the incremental pricing regulations in Part 282 may be granted upon a showing by the applicant that relief is necessary to prevent special hardship, inequity or unfair distribution of burdens. The Commission has the capability of rapidly processing a § 1.41 petition for relief and believes it will be able to handle any such petitions in an expeditious and equitable manner.

However, the Commission does not intend that the § 1.41 procedures should provide the vehicle for generalized challenges to Title II of the NGPA and the regulations promulgated thereunder. The § 1.41 procedures have been adopted by the Commission simply to provide an avenue of administrative relief for parties which are uniquely affected by Commission regulations, and not to provide an arena for inquiries into policy questions of broad applicability.

The three comments which opposed the establishment of a rulemaking proceeding in this docket stated reasons generally consistent with those described above for not proceeding any further with a rulemaking to exempt load-balancing facilities which have the capability to burn oil.

For the reasons stated in this notice, a rulemaking regarding an exemption from incremental pricing for load-balancing facilities which have the capability to burn oil will not be initiated. The Commission hereby gives notice that Docket No. RM79-46 is terminated.

By direction of the Commission.

Lois D. Cashell,
Acting Secretary.

Appendix

Following is a list of those who submitted comments in Docket No. RM79-46:

The American Gas Association
Associated Gas Distributors
Brooklyn Union Gas Company
Connecticut Natural Gas Corporation
Mountain Fuel Supply Company
Natural Gas Pipeline Company of America
Northern Indiana Public Service Company
The Peoples Gas Light and Coke Company
Philadelphia Gas Works
The Process Gas Consumers Group, the Georgia Industrial Gas Group, and The American Iron and Steel Institute
Public Service Company of Colorado
State of Wisconsin Public Service Commission
Southern Company Services, Inc.
The United Distribution Companies
The Wisconsin Distributor Group
Wisconsin Gas Company

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federal register

Friday
October 5, 1979

Part V

Environmental Protection Agency

Automobile and Light-Duty Truck Surface Coating Operations; Standards of Performance and Addition to the List of Categories of Stationary Sources

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL-1285-4]

Automobile and Light-Duty Truck Surface Coating Operations; Standards of Performance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Standards of performance are proposed to limit emissions of volatile organic compounds (VOC) from new, modified, and reconstructed automobile and light-duty truck surface coating operations within assembly plants. Three new test methods are also proposed. Reference Method 24 (Candidate 1 or Candidate 2) would be used to determine the VOC content of coating materials, and Reference Method 25 would be used to determine the percentage reduction of VOC emissions achieved by add-on emission control devices.

The standards implement the Clean Air Act and are based on the Administrator's determination that automobile and light-duty truck surface coating operations within assembly plants contribute significantly to air pollution. The intent is to require new, modified, and reconstructed automobile and light-duty truck surface coating operations to use the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

A public hearing will be held to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments.* Comments must be received on or before December 14, 1979.

Public Hearing. The public hearing will be held on November 9, 1979, at 9 a.m.

Request to Speak at Hearing. Persons wishing to present oral testimony should contact EPA by November 2, 1979

ADDRESSES: *Comments.* Comments should be submitted to: Central Docket Section (A-130), Attention: Docket Number A-79-05, U.S. Environmental Protection Agency, 401 M Street SW., Washington, D.C. 20460.

Public Hearing. The public hearing will be held at National Environmental Resource Center (NERC), Rm. B-102, R.T.P., N.C. Persons wishing to present oral testimony should notify Ms. Shirley Tabler, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5421.

Background Information Document. The Background Information Document (BID) for the proposed standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Automobile and Light-Duty Truck Surface Coating Operations—Background Information for Proposed Standards," EPA-450/3-79-030.

Docket. The Docket, number A-79-05, is available for public inspection and copying at the EPA's Central Docket Section, Room 2903 B, Waterside Mall, Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Proposed Standards

The proposed standards would apply to new automobile and light-duty truck surface coating operations. Existing plants would not be covered unless they undergo modifications resulting in increased emissions or reconstructions. The proposed standards would apply to each prime coat operation, each guide coat operation, and each topcoat operation within an assembly plant. Emissions of VOC from each of these operations would be limited as follows: 0.10 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from prime coat operations, 0.84 kilogram of VOC (measured as mass of carbon) per liter applied coating solids from guide coat operations, 0.84 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from topcoat operations.

These proposed emission limits are based on Method 24 (Candidate 1) which determines VOC content of coatings expressed as the mass of carbon. At the time the standards were developed, it was believed that VOC emissions should be determined from carbon measurements. Method 24 (Candidate 1) was developed to measure carbon directly and thus improve the accuracy of the previously used ASTM procedure D 2369-73, which measures the mass of volatile organics indirectly. However, questions have been raised concerning the validity of using the carbon method since the ratio of mass of carbon to mass of VOC in solvents used in automotive coatings varies over a wide range. The effect which this variation might have on the standards is still being investigated. Method 24 (Candidate 2) was developed as a test method for determining VOC emissions from coating materials in terms of mass of volatile organics and is also derived from ASTM procedure D 2369-73. The proposed emission limits, based on Method 24 (Candidate 2) which measures volatile organics, are: 0.16 kilogram of VOC per liter of applied coating solids from prime coat operations, and 1.36 kilogram of VOC per liter of applied coating solids for guide coat operations, and 1.36 kilogram of VOC per liter of applied coating solids from top coat operations. In order to provide an opportunity for public comment on both test methods, both are being proposed, and the final selection of a test method will be made before promulgation, based on the comments received.

Although the emission limits are based on the use of water-based coating materials in each coating operation, they can also be met with solvent-based coating materials through the use of other control techniques, such as incineration. Exemptions are included in the proposed standards which specifically exclude annual model changeovers from consideration as modifications.

Summary of Environmental, Energy, and Economic Impacts

Environmental, energy, and economic impacts of standards of performance are normally expressed as incremental differences between the impacts from a facility complying with the proposed standard and those for one complying with a typical State Implementation Plan (SIP) emission standard. In the case of automobile and light-duty truck surface coating operations, the incremental differences will depend on the control levels that will be required by revised SIP's. Revisions to most SIP's are currently in progress.

Most existing automobile and light-duty truck surface coating operations are located in areas which are considered nonattainment areas for purposes of achieving the National Ambient Air Quality Standard (NAAQS) for ozone. New facilities are expected to locate in similar areas. States are in the process of revising their SIP's for these areas and are expected to include revised emission limitations for automobile and light-duty truck surface coating operations in their new SIP's. In revising their SIP's the States are relying on the control techniques guideline document, "Control of Volatile Organic Emissions from Existing Stationary Sources—Volume II: Surface Coating of Cans, Coil, Paper, Fabrics, Automobiles and Light-Duty Trucks" (EPA-450/2-77-088 [CTG]).

Since control technique guidelines are not binding, States may establish emission limits which differ from the guidelines. To the extent States adopt the emission limits recommended in the control techniques guideline document as the basis for their revised SIP's, the proposed standards of performance would have little environmental, energy, or economic impacts. The actual incremental impacts of the proposed standards of performance, therefore, will be determined by the final emission limitations adopted by the States in their revised SIP's. For the purpose of this rulemaking, however, the environmental, energy, and economic impacts of the proposed standards have been estimated based on emission limits contained in existing SIP's.

In addition to achieving further reductions in emissions beyond those required by a typical SIP, standards of performance have other benefits. They establish a degree of national uniformity to avoid situations in which some States may attract industries by relaxing air pollution standards relative to other States. Further, standards of performance improve the efficiency of case-by-case determinations of best available control technology (BACT) for facilities located in attainment areas, and lowest achievable emission rates (LAER) for facilities located in nonattainment areas, by providing a starting point for the basis of these determinations. This results from the process for developing a standard of performance, which involves a comprehensive analysis of alternative emission control technologies and an evaluation and verification of emission test methods. Detailed cost and economic analyses of various regulatory alternatives are presented in the supporting documents for standards of performance.

Based on emission control levels contained in existing SIP's, the proposed standards of performance would reduce emissions of VOC from new, modified, or reconstructed automobile and light-duty truck surface coating operations by about 80 percent. National emissions of VOC would be reduced by about 4,800 metric tons per year by 1983.

Water pollution impacts of the proposed standards would be relatively small compared to the volume and quality of the wastewater discharged from plants meeting existing SIP levels. The proposed standards are based on the use of water-based coating materials. These materials would lead to a slight increase in the chemical oxygen demand (COD) of the wastewater discharged from the surface coating operations within assembly plants. This increase in COD, however, is not great enough to require additional wastewater treatment capacity beyond that required in existing assembly plants using solvent-based surface coating materials.

The solid waste impact of the proposed standards would be negligible compared to the amount of solid waste generated by existing assembly plants. The solid waste generated by water-based coatings, however, is very sticky, and equipment cleanup is more time consuming than for solvent-based coatings. Solid wastes from water-based coatings do not present any special disposal problems since they can be disposed of by conventional landfill procedures.

National energy consumption would be increased by the use of water-based coatings to comply with the proposed standards. The equivalent of an additional 18,000 barrels of fuel oil would be consumed per year at a typical assembly plant. This is equivalent to an increase of about 25 percent in the energy consumption of a typical surface coating operation. National energy consumption would be increased by the equivalent of about 72,000 barrels of fuel oil per year in 1983. This increase is based on the projection that four new assembly plants will be built by 1983.

The proposed standards would increase the capital and annualized costs of new automobile and light-duty truck surface coating operations within assembly plants. Capital costs for the four new facilities planned by 1983 would be increased by approximately $19 million as a result of the proposed standards. The incremental capital costs for control represent about 0.2 percent of the $10 billion planned for capital expenditures. The corresponding annualized costs would be increased by approximately $9 million in 1983. The price of an automobile or light-duty truck manufactured at a new plant which complies with the proposed standards of performance would be increased by less than 1 percent. This is considered to be a reasonable control cost.

Modifications and Reconstructions

During the development of the proposed standards, the automobile industry expressed concern that changes to assembly plants made only for the purpose of annual model changeovers would be considered a modification or reconstruction as defined in the Code of Federal Regulations, Title 40, Parts 60.14 and 60.15 (40 CFR 60.14 and 60.15). A modification is any physical or operational change in an existing facility which increases air pollution from that facility. A reconstruction is any replacement of components of an existing facility which is so extensive that the capital cost of the new components exceeds 50 percent of the capital cost of a new facility. In general, modified and reconstructed facilities must comply with standards of performance. According to the available information, changes to coating lines for annual model changeovers do not cause emissions to increase significantly. Further, these changes would normally not require a capital expenditure that exceeds the 50 percent criterion for reconstruction. Hence, it is very unlikely that these annual facility changes would be considered either modifications or reconstructions. Therefore, the proposed standards state that changes to surface coating operations made only to accommodate annual model changeovers are not modifications or reconstructions. In addition, by exempting annual model changeovers, enforcement efforts are greatly reduced with little or no adverse environmental impact.

Selection of Source and Pollutants

VOC are organic compounds which participate in atmospheric photochemical reactions or are measured by Reference Methods 24 (Candidate 1 or Candidate 2) and 25. There has been some confusion in the past with the use of the term "hydrocarbons." In addition to being used in the most literal sense, the term "hydrocarbons" has been used to refer collectively to all organic chemicals. Some organics which are photochemical oxidant precursors are not hydrocarbons (in the strictest definition) and are not always used as solvents. For purposes of this discussion, organic compounds include all compounds of carbon except carbonates, metallic carbides, carbon monoxide, carbon dioxide and carbonic acid.

Ozone and other photochemical oxidants result in a variety of adverse impacts on health and welfare, inducing impaired respiratory function, eye irritation, deterioration of materials such as rubber, and necrosis of plant tissue. Further information on these effects can be found in the April 1978 EPA document "Air Quality Criteria for Ozone and Other Photochemical Oxidants," EPA-600/8-78-004. This document can be obtained from the EPA library (see Addresses Section).

Industrial coating operations are a major source of air pollution emissions of VOC. Most coatings contain organic solvents which evaporate upon drying of the coating, resulting in the emission of VOC. Among the largest individual operations producing VOC emissions in the industrial coating category are automobile and light-duty truck surface coating operations. Since the surface coating operations for automobiles and light-duty trucks are very similar in nature, with line speed being the primary difference, they are being considered together in this study. Automobile and light-duty truck manufacturers employ a variety of surface coatings, most often enamels and lacquers, to produce the protective and decorative finishes of their product. These coatings normally use an organic solvent base, which is released upon drying.

The "Priority List for New Source Performance Standards under the Clean Air Act Amendments of 1977," which was promulgated in 40 CFR 60.16, 44 FR 49222, dated August 21, 1979, ranked sources according to the impact that standards promulgated in 1980 would have on emissions in 1990. Automobile and light-duty truck surface coating operations rank 27 out of 59 on this list of sources to be controlled.

The surface coating operation is an integral part of an automobile or light-duty truck assembly plant, accounting for about one-quarter to one-third of the total space occupied by a typical assembly plant. Surface coatings are applied in two main steps, prime coat and topcoat. Prime coats may be water-based or organic solvent-based. Water-based coatings use water as the main carrier for the coating solids, although these coatings normally contain a small amount of organic solvent. Solvent-based coatings use organic solvent as the coating solids carrier. Currently about half of the domestic automobile and light-duty truck assembly plants use water-based prime coats.

Where water-based prime coating is used, it is usually applied by EDP. The EDP coat is normally followed by a "guide coat," which provides a suitable surface for application of the topcoat. The guide coat may be water-based or solvent-based.

Automobile and light-duty truck topcoats presently being used are almost entirely solvent-based. One or more applications of topcoats are applied to ensure sufficient coating thinkness. An oven bake may follow each topcoat application, or the coating may be applied wet on wet.

In 1976, nationwide emissions of VOC from automobile and light-duty truck surface coating operations totaled about 135,000 metric tons. Prime and guide coat operations accounted for about 50,000 metric tons with the remaining 85,000 metric tons being emitted from topcoat operations. This represents almost 15 percent of the volative organic emissions from all industrial coating operations.

VOC comprise the major air pollutant emmitted by automobile and light-duty truck assembly plants. Technology is available to reduce VOC emissions and thereby reduce the formation of ozone and other photochemical oxidants. Consequently, automobile and light-duty truck surface coating operations have been selected for the development of standards of performance.

Selection of Affected Facilities

The prime coat, guide coat, and topcoat operations usually account for more than 80 percent of the VOC emissions from autombile and light-duty truck assembly plants. The remaining VOC emissions result from final topcoat repair, cleanup, and coating of various small component parts. These VOC emission sources are much more difficult to control than the main surface coating operations for several reasons. First, water-based coatings cannot be used for final topcoat repair, since the high temperatures required to cure water-based coatings may damage heat sensitive components which have been attached to the vehicle by this stage of production. Second, the use of solvents is required for equipment cleanup procedures. Third, add-on controls, such as incineration, cannot be used effectively on these cleanup operations because they are composed of numerous small operations located throughout the plant. Since prime coat, guide coat, and topcoat operations account for the bulk of VOC emissions from autombile and light-duty truck assembly plants, and control techniques for reducing VOC emissions from these operations are demonstrated, they have been selected for control by standards of performance.

The "affected facility" to which the proposed standards would apply could be designated as the entire surface coating line or each individual surface coating operation. A major consideration in selecting the affected facility was the potential effect that the modification and reconstruction provisions under 40 CFR 60.14 and 60.15, which apply to all standards of performance, could have on existing assembly plants. A modification is any physical or operational change in an existing facility which increases air pollution from that facility. A reconstruction is any replacement of components of an existing facility which is so extensive that the capital cost of the new componensts exceeds 50 percent of the capital cost of a new facility. For standards of performance to apply, EPA must conclude that it is technically and economically feasible for the reconstructed facility to meet the standards.

Many automobile and light-duty truck assembly plants that have a spray prime coat system will be switching to EDP prime coat systems in the future to reduce VOC emissions to comply with revised SIP's. The capital cost of this change could be greater than 50 percent of the capital cost of a new surface coating line. If the surface coating line were chosen as the affected facility, and if this switch to an EDP prime coat system were considered a reconstruction of the surface coating line, all surface coating operations on the line would be required to comply with the proposed standards. Most plants would be reluctant to install an EDP prime coat system to reduce VOC emissions if, by doing so, the entire surface coating line might then be required to comply with standards of performance. By designating the prime coat, guide coat, and topcoat operations as separate affected facilities, this potential problem is avoided. Thus, each surface coating operation (i.e., prime coat, guide coat, and topcoat) has been selected as an affected facility in the proposed standards.

Selection of Best System of Emission Reduction

VOC emissions from automobile and light-duty truck surface coating operations can be controlled by the use of coatings having a low organic solvent content, add-on emissions control devices, or a combination of the two. Low organic solvent coatings consist of water-based enamels, high solids enamels, and powder coatings. Add-on emission control devices consist of such techniques as incineration and carbon adsorption.

Control Technologies

Water-based coating materials are applied either by conventional spraying or by EDP. Application of coatings by EDP involves dipping the automobile or truck to be coated into a bath containing a dilute water solution of the coating material. When charges of opposite polarity are applied to the dip tank and vehicle, the coating material deposits on the vehicle. Most EDP systems presently in use are anodic systems in which the vehicle is given a positive charge.

Cathodic EDP, in which the vehicle is negatively charged, is a new technology which is expanding rapidly in the automotive industry. Cathodic EDP provides better corrosion resistance and requires lower cure temperatures than anodic systems. Cathodic EDP systems are also capable of applying better coverage on deep recesses of parts.

The prime coat is usually followed by a spray application of an intermediate coat, or guide coat, before topcoat application. The guide coat provides the added film thickness necessary for sanding and a suitable surface for topcoat application. EDP can only be used if the total film thickness on the metal surface does not exceed a limiting value. Since this limiting thickness is about the same as the thickness of the prime coat, spraying has to be used for guide coat and topcoat application of water-based coatings.

Currently, nearly half of domestic automobile and light-duty truck assembly plants use EDP for prime coat application, but only two domestic plants use water-based coating for guide coat and topcoat applications.

Coatings whose solids content is about 45 to 60 percent are being developed by a number of companies. When these coatings are applied at high transfer efficiency rates, VOC emissions are significantly less than emissions from existing solvent-based systems. While these high solids coatings could be used in the automotive industry, certain problems must be overcome. The high working viscosity of these coatings makes them unsuitable for use in many existing application devices. In addition, this high viscosity can produce an "orange peel," or uneven, surface. It also makes these coatings unsuitable for use with metallic finishes. Metallic finishes, which account for about 50 percent of domestic demand, are produced by adding small metal flakes to the paint. As the paint dries, these flakes become oriented parallel to the surface. With high solids coatings, the viscosity of the paint prevents movement of the flakes, and they remain randomly oriented, producing a rough surface. However, techniques such as heated application are being investigated to reduce these problems, and it is expected that by 1982 high solids coatings will be considered technically demonstrated for use in the automotive industry.

Powder coatings are a special class of high solids coatings that consist of solids only. They are applied by electrostatic spray and are being used on a limited basis for topcoating automobiles, both foreign and domestic. The use of powder coatings is severely limited, however, because metallic finishes cannot be applied using powder. As with other high solids coatings, research is continuing in the use of powder coatings for the automotive industry.

Thermal incineration has been used to control VOC emissions from bake ovens in automobile and light-duty truck surface coating operations because of the fairly low volume and high VOC concentration in the exhaust stream. Incineration normally achieves a VOC emission reduction of over 90 percent. Thermal incinerators have not, however, been used for control of spray booth VOC emissions. Typically, the spray booth exhaust stream is a high volume stream (95,000 to 200,000 liters per second) which is very low in concentration of VOC (about 50 ppm). Thermal incineration of this exhaust stream would require a large amount of supplemental fuel, which is its main drawback for control of spray booth VOC emissions. There are no technical problems with the use of thermal incineration.

Catalytic incineration permits lower incinerator operating temperatures and, therefore, requires about 50 percent less energy than thermal incineration. Nevertheless, the energy consumption would still be high if catalytic incineration were used to control VOC emissions from a spray booth. In addition, catalytic incineration allows the owner or operator less choice in selecting a fuel; it requires the use of natural gas to preheat the exhaust gases, since oil firing tends to foul the catalyst. While catalytic incineration is not currently being employed in automobile and light-duty truck surface coating operations for control of VOC emissions, there are no technical problems which would preclude its use on either bake oven or spray booth exhaust gases. The primary limiting factor is the high energy consumption of natural gas, if catalytic incineration is used to control emissions from spray booths.

Carbon adsorption has been used successfully to control VOC emissions in a number of industrial applications. The ability of carbon adsorption to control VOC emissions from spray booths and bake ovens in automobile and light-duty truck surface coating operations, however, is uncertain. The presence of a high volume, low VOC exhaust stream from spray booths would require carbon adsorption units much larger than any that have ever been built. For bake ovens in automobile and light-duty truck surface coating operations, a major impediment to the use of carbon adsorption is heat. The high temperature of the bake oven exhaust stream would require the use of refrigeration to cool the gas stream before it passes through the carbon bed. Carbon adsorption, therefore, is not considered a demonstrated technology at this time for controlling VOC emissions from automobile and light-duty truck surface coating operations. Work is continuing within the automotive industry on efforts to apply carbon adsorption to the control of VOC emissions, however, and it may become a demonstrated technology in the near future.

Regulatory Options

Water-based coatings and incineration are two well-demonstrated and feasible techniques for controlling emissions of VOC from automobile and light-duty truck surface coating operations. Based upon the use of these two VOC emission control techniques, the following two regulatory options were evaluated.

Regulatory Option I includes two alternatives which achieve essentially equivalent control of VOC emissions. Alternative A is based on the use of water-based prime coats, guide coats, and topcoats. The prime coat would be applied by EDP. Since the guide coat is essentially a topcoat material, guide coat emission levels as low as those achieved by water-based topcoats should be possible through a transfer of technology from topcoat operations to guide coat operations. Alternative B is based on the use of a water-based prime coat applied by EDP and solvent-based guide coats and topcoats. Incineration of the exhaust gas stream from the topcoat spray booth and bake oven would be used to control VOC emissions under this alternative.

Regulatory Option II is based on the use of a water-based prime coat applied by EDP and solvent-based guide coats and topcoats. In this option, the exhaust gas streams from both the guide coat and topcoat spray booths and bake ovens would be incinerated to control VOC emissions.

Environmental, Energy, and Economic Impacts

Standards based on Regulatory Option I would lead to a reduction in VOC emissions of about 80 percent, and standards based on Regulatory Option II would lead to a reduction in emissions of about 90 percent, compared to VOC emissions from automobile and light-duty truck surface coating operations controlled to meet current SIP requirements. Growth projections indicate there will be four new automobile and light-duty truck assembly lines constructed by 1983. Very few, if any, modifications or reconstructions are expected during this period. Based on these projections, national VOC emissions in 1983 would be reduced by about 4,800 metric tons with standards based on Regulatory Option I and about 5,400 metric tons with standards based on Regulatory Option II. Thus, both regulatory options would result in a significant reduction in VOC emissions from automobile and light-duty truck surface coating operations.

With regard to water pollution, standards based on Regulatory Option II would have essentially no impact. Similarly, standards based on Regulatory Option I(B) would have no water pollution impact. Standards based on Regulatory Option I(A), however, would result in a slight increase in the chemical oxygen demand (COD) of the wastewater discharged from automobile and light-duty truck surface coating operations within assembly plants. This increase is due to water-miscible solvents in the water-based guide coats and topcoats which become dissolved in the wastewater. The increase in COD of the wastewater, however, would be small relative to current COD levels at plants using solvent-based surface coatings and meeting existing SIP's. In addition, this increase would not require the installation of a larger wastewater treatment facility than would be built for an assembly plant which used solvent-based surface coatings.

The solid waste impact of the proposed standards would be negligible. The volume of sludge generated from water-based surface coating operations is approximately the same as that generated from solvent-based surface coating operations. The solid waste generated by water-based coatings, however, is very sticky, and equipment cleanup is more time consuming than for solvent-based coatings. Sludge from either type of system can be disposed of by conventional landfill procedures without leachate problems.

With regard to energy impact, standards based on Regulatory Option I(A) would increase the energy consumption of surface coating operations at a new automobile or light-duty truck assembly plant by about 25 percent. Regulatory Option I(B) would cause an increase of about 150 to 425 percent in energy consumption. Standards based on Regulatory Option II would result in an increase of 300 to 700 percent in the energy consumption of surface coating operations at a new automobile or light-duty truck assembly plant. The range in energy consumption for those options which are based on use of incineration reflects the difference between catalytic and thermal incineration.

The relatively high energy impact of standards based on Regulatory Option I(B) and Regulatory Option II is due to the large amount of incineration fuel needed. Standards based on Regulatory Option II would increase energy consumption at a new automobile and light-duty truck assembly plant by the equivalent of about 200,000 to 500,000 barrels of fuel oil per year, depending upon whether catalytic or thermal incineration was used. Standards based on Regulatory Option I(B) would increase energy consumption by the equivalent of about 100,000 to 300,000 barrels of fuel oil per year.

Standards based on Regulatory Option I(A) would increase the energy consumption of a typical new automobile and light-duty truck assembly plant by the equivalent of about 18,000 barrels of fuel oil per year. Approximately one-third of this increase in energy consumption is due to the use of air conditioning, which is necessary with the use of water-based coatings, and the remaining two-thirds are due to the increased fuel required in the bake ovens for curing water-based coatings.

Growth projections indicate that four new automobile and light-duty truck assembly lines (two automobile and two truck lines) will be built by 1983. Based on these projections, standards based on Regulatory Option I(A) would increase national energy consumption in 1983 by the equivalent of about 72,000 barrels of fuel oil. Standards based on Regulatory Option I(B) would increase national energy consumption in 1983 by the equivalent of 400,000 to 1,200,000 barrels of fuel oil, depending on whether catalytic or thermal incineration were used. Standards based on Regulatory Option II would increase national energy consumption in 1983 by the equivalent of 800,000 to 2,000,000 barrels of fuel oil, again depending on whether catalytic or thermal incineration were used.

The economic impacts of standards based on each regulatory option were estimated using the growth projection of four new assembly lines by 1983. Incremental control costs were determined by calculating the difference between the capital and annualized costs of new assembly plants controlled to meet Regulatory Options I(A), I(B), and II, respectively, with the corresponding costs for new plants designed to comply with existing SIP's. Of the four assembly plants projected by 1983, two were assumed to be lacquer lines and the other two enamel lines. There are basic design differences between these two types of surface coatings which have a substantial impact on the magnitude of the costs estimated to comply with standards of performance. Lacquer surface coating operations, for example, require much larger spray booths and bake ovens than enamel surface coating operations. Water-based systems also require large spray booths and bake ovens; thus, the incremental capital cost of installing a water-based system in a plant which would otherwise have used a lacquer system is relatively low. The incremental capital costs differential, however, would be much larger if the plant would have been designed for an enamel system.

Tables 1 and 2 summarize the economic impacts of the proposed standards on plants of typical sizes. Table 1 presents the incremental costs of the various control options for a plant which would have used solvent-based lacquers. Table 2 presents similar costs for plants which would have been designed to use solvent-based enamels. Though these tables present incremental costs for passenger car plants, light-duty truck plants would have similar cost differentials. In all cases, it is assumed the plants would install a water-based EDP prime system in the absence of standards of performance. Therefore, no incremental costs associated with EDP prime coat operations are included in the costs presented in Tables 1 and 2. A nominal production rate of 55 passenger cars per hour was assumed for both plants. Tables 1 and 2 show incremental capitalized and annualized costs per vehicle produced at each new facility. The manufacturers would probably distribute these incremental costs over their entire annual production to arrive at purchase prices for the automobiles and light-duty trucks.

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Table 1. INCREMENTAL CONTROL COSTS[a]

(Compared to the Costs of a Lacquer Plant)

	Regulatory Options				
	I(A)	I(B)		II	
	Water-Based Coatings	Thermal	Catalytic	Thermal	Catalytic
Capital Cost of Control Alternative	$ 720,000	$11,800,000	$15,000,000	$12,800,000	$16,200,000
Annualized Cost of Control Alternative	$1,550,000	$14,500,000	$10,700,000	$15,500,000	$11,500,000
Incremental Cost/Vehicle Produced at this Facility	$7.34	$68.66	$50.66	$73.39	$54.45

[a]Assumes a line speed of 55 vehicles per hour and an annual production of 211,200 vehicles.

Table 2. INCREMENTAL CONTROL COSTS[a]

(Compared to the Costs of an Enamel Plant)

	Regulatory Options				
	I(A)	I(B)		II	
	Water-Based Coatings	Thermal	Catalytic	Thermal	Catalytic
Capital Cost of Control Alternative	$10,300,000	$ 4,630,000	$ 5,850,000	$ 5,640,000	$ 7,000,000
Annualized Cost of Control Alternative	$ 3,640,000	$ 5,620,000	$ 4,150,000	$ 6,610,000	$ 4,890,000
Incremental Cost/Vehicle Produced at this Facility	$17.23	$26.61	$19.65	$31.30	$23.15

[a]Assumes a line speed of 55 vehicles per hour and an annual production of 211,200 vehicles.

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Incremental capital costs for suing incineration to reduce VOC emissions from solvent-based lacquer plants to levels comparable to water-based plants are much larger than they are for using incineration on a solvent-based enamel plant. This large difference in costs occurs because lacquer plants have larger spray booth and bake oven areas than enamel plants and, therefore, a larger volume of exhaust gases. Since larger incineration units are required, the incremental capital costs of using incineration to control VOC emissions from a solvent-based lacquer plant are about 15 to 25 times greater than they are for using water-based coatings. Similarly, energy consumption is much greater; hence, the annualized costs of using incineration are about 10 times greater than they are for using water-based coatings.

On the other hand, the incremental capital costs of controlling VOC emissions from new solvent-based enamel plants by the use of incineration are only about one-half the incremental capital costs between a new solvent-based enamel plant and a new water-based plant. Due to the energy consumption associated with incinerators, however, the incremental annualized costs of using incineration with solvent-based enamel coatings could vary from as little as 15 percent more to as much as 90 percent more than the annualized costs of using water-based coatings.

While the incremental capital costs of building a plant to use water-based coatings can be larger or smaller than the costs of using incineration, depending upon whether a solvent-based lacquer plant or a solvent-based enamel plant is used as the starting point, the annualized costs of using water-based coatings are always less than they are for using incineration. This is due to the large energy consumption of incineration units compared to the energy consumption of water-based coatings.

Since the incremental annualized costs are less with Regulatory Option I(A) than with Regulatory Option I(B), it is assumed in this analysis that Regulatory Option I(A) would be incorporated at any new, modified, or reconstructed facility to comply with standards based on Regulatory Option I. As noted, four new assembly plants are expected to be built by 1983. The incremental capital cost to the industry for these plants to comply with standards based on Regulatory Option I would be approximately $19 million. The corresponding incremental annualized costs would be about $9 million in 1983.

If standards are based on Regulatory Option II, it is expected that the industry would choose catalytic incineration because its annualized costs are lower than those for thermal incineration. Based this assumption, the incremental capital costs for the industry under Regulatory Option II would be approximately $42 million, and the incremental annualized costs by 1983 would be about $30 million. For standards based on either Regulatory Option I or Regulatory Option II, the increase in the price of an automobile or light-duty truck that is manufactured at one of the new plants would be less than 1 percent of the base price of the vehicle.

Best System of Emission Reduction

Both Regulatory Options I and II achieve a significant reduction in VOC emissions compared to automobile and light-duty truck assembly plants controlled to comply with existing SIP's, and neither option creates a significant adverse impact on other environmental media. In terms of energy consumption, standards based on Regulatory Option II would have as much as 10 to 25 times the adverse impact on energy consumption as standards based on Regulatory Option I, while only achieving 10 to 15 percent more reductions in VOC emissions. The costs of standards based on Regulatory Option II range from two to three times the costs of standards based on Regulatory Option I. Thus, Regulatory Option I(A), water-based coatings, was selected as the best system of continuous emission reduction, considering costs and nonair quality health, and environmental and energy impacts.

Although water-based coatings are considered to be the best system of emission reduction at the present time, it is very likely that plants built in the future will use other systems to control VOC emissions, such as high solids coatings and powder coatings. High solids coatings applied at high transfer efficiencies are capable of achieving equivalent emission reductions and are expected to be less costly and require less total energy than water-based systems. These high solids coatings are expected to be available by 1982 and will probably be used by most new sources to comply with the VOC emission limitations. Powder coatings are also expected to be available in the future but are not demonstrated at this time.

Selection of Format for the Proposed Standards

A number of different formats could be selected to limit VOC emissions from automobile and light-duty truck surface coating operations. The format ultimately selected must be compatible with any of the three different control systems that could be used to comply with the proposed standards. One control system is the use of water-based coating materials in the prime coat, guide coat, and topcoat operations. Another control system is the use of solvent-based coating materials and add-on VOC emission control devices such as incineration. The third control system consists of the use of high solids coatings. Although the coatings to be used in this system are not demonstrated at this time, research is continuing toward their development; hence, they may be used in the future.

The formats considered were emission limits expressed in terms of (1) concentration of emissions in the exhaust gases discharged to the atmosphere; (2) mass emissions per unit of production; or (3) mass emissions per volume of coating solids applied.

The major advantage of the concentration format is its simplicity of enforcement. Direct emission measurements could be made using Reference Method 25. There are, however, two significant drawbacks to the use of this format. Regardless of the control approach chosen, emission testing would be required for each stack exhausting gases from the surface coating operations (unless the owner or operator could demonstrate to the Administrator's satisfaction that testing of representative stacks would give the same results as testing all the stacks). This testing would be time consuming and costly because of the large number of stacks associated with automobile and light-duty truck surface coating operations. Another potential problem with this format is the ease of circumventing the standards by the addition of dilution air. It would be extremely difficult to determine whether diluted air was being added intentionally to reduce the concentration of VOC emissions in the gases discharged to the atmosphere, or whether the air was being added to the application or drying operation to optimize performance and maintain a safe working space.

A format of mass VOC emissions per unit of production relates emissions to individual plant production on a direct basis. Where water-based coatings are used, the average VOC content of the coating materials could be determined by using Reference Method 24 (Candidate 1 or Candidate 2). The volume of coating materials used and the percent solids could be determined from purchase records. VOC emissions could then be calculated by multiplying the VOC content of the coating materials by the volume of coating materials used in a given time period and by the percentage of solids, and dividing the result by the number of vehicles produced in that time period. This would provide a VOC emission rate per unit of production. Consequently, procedures to determine compliance would be direct and straightforward, although very time consuming. This procedure would also require data collection over an excessively long period of time.

Where solvent-based coatings were used with add-on emission control devices, stack emission tests could be performed to determine VOC emissions. Dividing VOC emissions by the number of vehicles produced would again yield VOC emissions per unit of production. This format, however, would not account for differences in surface coating requirements for different vehicles caused by size and configuration. In addition, manufactureres of larger vehicles would be required to reduce VOC emissions more than manufacturers of smaller vehicles.

A format of mass of VOC emissions per volume of coating solids applied also has the advantage of not requiring stack emission testing unless add-on emission control devices rather than water-based coatings are used to comply with the standards. The introduction of dilution air into the exhaust stream would not present a problem with this format. The problem of varying vehicle sizes and configurations would be eliminate since the format is in terms of volume of applied solids regardless of the surface area or number of vehicles coated. This format would also allow flexibility in selection of control systems, for it is usable with any of the control methods. Since this format overcomes the varying dilution air and vehicle size problems inherent with the other formats, it has been selected as the format for the proposed standards. In order to use a format which is in terms of applied solids, the transfer efficiency of the application devices must be considered. Transfer efficiency is defined as the fraction of the total sprayed solids which remain on the vehicle. Transfer efficiency is an important factor because as efficiency decreases, more coating material is used and VOC emissions increase. Equations have been developed to use this format with water-based coating materials as well as with solvent-based coating materials in combination with high transfer efficiences and/or add-on emission controls devices. These equations are included in the proposed standards.

Selection of Numerical Emission Limits

Numerical Emission Limits

The numerical emission limits selected for the proposed standard are:

- 0.10 kilogram of VOC per liter of applied coating solids from prime coat operations
- 0.84 kilogram of VOC per liter of applied coating solids from guide coat operations
- 0.84 kilogram of VOC per liter of applied coating solids from topcoat operations

In all three limits, the mass of VOC is measured as carbon in accordance with Reference Methods 24 (Candidate 1) and 25. These emission limits are based on the use of water-based coating materials in the prime coat, guide coat, and topcoat operations. Water-based coating data were obtained from plants which were using these materials as well as from the vendors who supply them. These data were used to calculate VOC emission limits using a procedure similar to proposed Method 24 (Candidate 1). A transfer efficiency of 40 percent was then applied to the values obtained for guide coat and top-coat emissions. This efficiency was determined to be representative of a well-operated air-atomized spray system. The CTG-recommended limits are based on the use of the same coating materials as the proposed standards. The limits in the CTG are expressed in pounds of VOC per gallon of coating (minus water) used in the EDP system or the spray device. The limits in these proposed standards, however, are referenced to the amount of coating solids which adhere to the vehicle body. Therefore, to compare the limits in the CTG to those proposed here, it is necessary to account for the solids content of the coating and the efficiency of applying the guide coat and topcoat to the vehicle body. Consideration of transfer efficiency is significant because the proposed standards can be met by using high solids content coating materials if the amount of overspray is kept to a minimum. Since this format provides equivalency determinations for systems using solvent-based coating materials in combination with high transfer efficiencies and/or add-on control devices, it allows flexibility in selection of control systems.

As discussed in previous sections, there are two types of EDP systems. Anodic EDP was the first type developed for use in automobile surface coating operations. Cathodic EDP is the second type and is a recent technology improvement which results in greater corrosion resistance. Consequently, nearly 50 percent of the existing EDP operations use cathodic systems, and continued changeovers from anodic to cathodic EDP are expected. Since cathodic EDP produces a coating with better corrosion resistance, the proposed standards are based on the best available cathodic EDP systems.

The coating material on which the EDP emission limit is based is presently in production use. Although this low solvent content material is currently available only in limited quantities, it is expected to be available in sufficient quantities for use in all new or modified sources before promulgation of the standard. The final promulgated standards will be based on this low solvent content material, rather than the EDP material commonly used now, if it is determined to be widely available at that time.

The emission limit for guide coat operations is based on a transfer of technology from topcoat operations. The guide coat is essentially a topcoat material, without pigmentation, and water-based topcoats are available which can comply with the proposed limits. Hence, the same emission limit is proposed for the guide coat operation as for the topcoat operation.

Because of the elevated temperatures present in the prime coat, guide coat, and topcoat bake ovens, additional amounts of "cure volatile" VOC may be emitted. These "cure volatile" emissions are present only at high temperatures and are not measured in the analysis which is used to determine the VOC content of coating materials. Cure volatile emissions, however, are believed to constitute only a small percentage of total VOC emissions. Consequently, because of the complexity of measuring and controlling cure volatile emissions, they will not be considered in determining compliance with the proposed standards.

A large number of coating materials are used in topcoat operations, and each may have a different VOC content. Hence, an average VOC content of all the coatings used in this operation would be computed to determine compliance with the proposed standards. Either of two averaging techniques could be used for computing this average. Weighted averages provide very accurate results but would require keeping records of the total volume and percent solids of each different coating used. Arithmetic averages are not always as accurate; however, they are much simpler to calculate. In the case of topcoat operations, normally 15 to 20 different coatings are used, and the VOC content for most of these coatings is in the same general range. Therefore, an arithmetic average would closely approximate the values obtained from a weighted average. An arithmetic average would be calculated by summing the VOC content of each surface coating material used in a surface coating operation (i.e., guide coat or topcoat), and dividing the sum by the number of different coating materials used. Arithmetic averages are also consistent with the approach being incorporated into some revised SIP's.

For the EDP process, however, an arithmetic average VOC content is not appropriate to determine compliance with the proposed standards. In an EDP system, the coating material applied to an automobile or light-duty truck body is replaced by adding fresh coating materials to maintain a relatively constant concentration of solids, solvent, and fluid level in the EDP coating tank. Three different types of materials are usually added in separate streams—clear resin, pigment paste, and solvent.

The clear resin and pigment paste are very low in VOC content (i.e., 10 percent or less), while the solvent is very high in VOC content (i.e., 90 percent or more). The solvent additive stream is only about 2 percent of the total volume added. Consequently, an arithmetic average of the three streams seriously misrepresents the actual amount of VOC added to the EDP coating tank. Weighted averages, therefore, were selected for determining the average VOC content of coating materials applied by EDP.

If an automobile or light-duty truck manufacturer chooses to use a control technique other than water-based coatings, the transfer efficiency of the application devices used becomes very important. As transfer efficiency decreases, more coating material is used and VOC emissions increase. Therefore transfer efficiency must be taken into account to determine equivalency to water-based coatings.

Electrostatic spraying, which applies surface coatings at high transfer efficiences, can in many industries be used with water-based coatings if the entire paint handling system feeding the atomizers is insulated electically from ground. Otherwise, the high conductivity of the water involved would ground out and make ineffective the electrostatic effect. In the case of the coating of automobiles, however, because of the larger number of colors involved, the high frequency and speed of color changes required, the large volume of coatings consumed per shift, and the large number of both automatic and manual atomizers involved, it is not technically feasible to combine water-based coatings and electrostatic methods for reasons of complexity, cost, and personnel comfort. Consequently, water-based surface coatings are applied by air-atomized spray systems at a transfer efficiency of about 40 percent. The numerical emission limits included in the proposed standards were developed based on the use of water-based surface coatings applied at a 40 percent transfer efficiency. Therefore, if surface coatings are applied to a greater than 40 percent transfer efficiency, surface coatings with higher VOC contents may be used with no increase in VOC emissions to the atmosphere. Transfer efficiencies for various means of applying surface coatings have been estimated, based on information obtained from industries and vendors, as follows:

Application method:	Transfer efficiency (percent)
Air Atomized Spray	40
Manual Electrostatic Spray	75
Automatic Electrostatic Spray	95
Electrodeposition (EDP)	100

These values are estimates which reflect the high side of expected transfer efficiency ranges, and therefore, are intended to be used only for the purpose of determining compliance with the proposed standards.

Frequently, more than one application method is used within a single surface coating operation. In these cases, a weighted average transfer efficiency, based on the relative volume of coating sprayed by each method, will be estimated. These situations are likely to vary among the different manufacturers and the estimates, therefore, will be subject to approval by the Administrator on a case-by-case basis.

Method of Determining Compliance

The procedure for determining compliance with the proposed standards is complicated due to the number of different control systems which may be used. The following multistep procedure would be used.

1. Determine the average VOC content per liter of coating solids of the prime coat, guide coat, and topcoat materials being used. This would require analyzing all coating materials used in each coating operation using the proposed Reference Method 24 (Candidate 1 or Candidate 2) and calculating an average VOC content for each coating operation.
2. Select the appropriate transfer efficiency for each surface coating operation from the table included in the proposed standards.
3. Calculate the mass of VOC emissions per volume of applied solids for each surface coating operation by dividing the appropriate average VOC content of the coatings (Step 1) by the transfer efficiency of the surface coating operation (Step 2). If the value obtained is lower than the emission limit included in the proposed standards, the surface coating operation would be in compliance. If the value obtained is higher than the emission limit, add-on VOC emission control would be required to comply with the proposed standards.
4. If add-on emission control is required, calculate the emission reduction efficiency in VOC emissions which is required using the equations included in the proposed standards.
5. In cases where all exhaust gases are not vented to an emission control device, determine the percentage of total VOC emissions which enter the add-on emission control device by sampling all the stacks and using the equations included in the proposed standards. Representative sampling, however, could be approved by the Administrator, on a case-by-case basis, rather than requiring sampling of all stacks for this determination.
6. Calculate the actual efficiency of the control device by determining VOC emissions before and after the device using the proposed Reference Method 25.
7. Calculate the VOC emission reduction efficiency achieved by multiplying the percentage of VOC emissions which enter the add-on VOC emission control device (Step 5) by the add-on control device efficiency (Step 6). If the resulting value of the emission reduction efficiency achieved were greater than that required (Step 4), then the surface coating operation would be in compliance.

Detailed instructions, as well as the equations to be used for these calculations, are contained in the proposed standards.

Selection of Monitoring Requirements

Monitoring requirements are generally included in standards of performance to provide a means for enforcement personnel to ensure that emission control measures adopted by a facility to comply with standards of performance are properly operated and maintained. Surface coating operations which have achieved compliance with the proposed standards without the use of add-on VOC emission control devices would be required to monitor the average VOC content (weighted averages for EDP and arithmetic averages for guide coat and topcoat) of the coating materials used in each surface coating operation. Generally, increases in the VOC content of the coating materials would cause VOC emissions to increase. These increases could be caused by the use of new coatings or by changes in the composition of existing coatings. Therefore, following the initial performance test, increases in the average VOC content of the coating materials used in each surface coating operation would have to be reported on a quarterly basis.

Where add-on control devices, such as incinerators, were used to comply with the proposed standards, combustion temperatures would be monitored. Following the initial performance test, decreases in the incinerator combustion temperature would be reported on a quarterly basis.

Performance Test Methods

Reference Method 24, "Determination of Volatile Organic Compound Content of Paint, Varnish, Lacquer, or Related Products," is proposed in two forms—Candidate 1 and Candidate 2. Candidate 1 leads to a determination of VOC content expressed as the mass of carbon. Candidate 2 yields a determination of VOC content measured as mass of volatile organics. The decision as to which Candidate will be used depends on the final format selected for the proposed standards. Reference Method 25, "Determination of Total Gaseous Nonmethane Volatile Organic Compound Emissions," is proposed as the test method to determine the percentage reduction of VOC emissions achieved by add-on emission control devices.

Public Hearing

A public hearing will be held to discuss the proposed standards in accordance with Section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address given above (see Addresses Section). Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement before, during, or within 30 days after the hearing. Written statements should be addressed to "Docket" (see Addresses Section).

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

Docket

The docket, containing all supporting information used by EPA to date, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

The docket is an organized and complete file of all the information submitted to or otherwise considered by EPA in the development of the rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the promulgated rule and EPA responses to significant comments, the contents of the Docket will serve as the record in case of judicial review [Section 307(d)(a)].

Miscellaneous

As prescribed by Section 111, establishment of standards of performance for automobile and light-duty truck surface coating operations was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of these standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. The Administrator welcomes comments on all aspects of the proposed regulations, including the technological issues, monitoring requirements, and the proposed test methods. Comments are requested specifically on Method 24 (Candidate 1 and Candidate 2) and the coating material used as the basis for the prime coat emission limit.

It should be noted that standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> . . . application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [Section 111(a)(1)].

Although emission control technology may be available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance because of costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act may require the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not necessarily play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources locating in nonattainment areas (i.e., those areas where statutorily mandated health and welfare standards are being violated). In this respect, section 173 of the Act requires that new or modified sources constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the LAER, as defined in section 171(3). The statute defines LAER as the rate of emissions based on the following, whichever is more stringent:

> (A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or
>
> (B) the most stringent emission limitation which is achieved in practice by such class or category of source.

In no event can the emission rate exceed any applicable new source performance standard.

A similar situation may arise under the prevention-of-significant-deterioration-of-air-quality provisions of the Act. These provisions require that certain sources employ BACT as defined in section 169(3) for all pollutants regulated under the Act. BACT must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all cases, SIP's approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of NAAQS designed to protect public health and welfare. For this purpose, SIP's must, in some cases, require greater emission reduction than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Under EPA's sunset policy for reporting requirements in regulations, the reporting requirements in this regulation will automatically expire 5 years from the date of promulgation unless EPA takes affirmative action to extend them.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance under section 111(b) of the Act. An economic impact assessment was prepared for the proposed regulations and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the proposed standards to ensure that the proposed standards would represent the best system of emission reduction considering costs. The economic impact assessment is included in the Background Information Document.

Dated: September 27, 1979.

Douglas M. Costle,

Administrator.

This proposed amendment to Part 60 of Chapter I, Title 40 of the Code of Federal Regulations would—

1. Add a definition of the term "volatile organic compound" to § 60.2 of Subpart A—General Provisions as follows:

§ 60.2 Definitions.

* * * * *

(dd) "Volatile Organic Compound" means any organic compound which participates in atmospheric photochemical reaction or is measured by the applicable reference methods specified under any subpart.

2. Add Subpart MM as follows:

Subpart MM—Standards of Performance for Automobile and Light-Duty Truck Surface Coating Operations

Authority: Secs. 111 and 301(a) of the Clean Air Act, as amended, [42 U.S.C. 7411, 7601(a)], and additional authority as noted below.

Subpart MM—Standards of Performance for Automobile and Light-Duty Truck Surface Coating Operations

§ 60.390 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to the following affected facilities in an automobile or light-duty truck surface coating line: each prime coat operation, each guide coat operation, and each topcoat operation.

(b) The provisions of this subpart apply to any affected facility identified in paragraph (a) of this section that begins construction or modification after ———— (date of publication in the Federal Register).

§ 60.391 Definitions.

All terms used in this subpart that are not defined below have the meaning given to them in the Act and in Subpart A of this part.

(a) "Automobile" means a motor vehicle capable of carrying no more than 12 passengers.

(b) "Automobile and light-duty truck body" means the body section rearward of the windshield and the front-end sheet metal or plastic exterior panel material forward of the windshield of an automobile or light-duty truck.

(c) "Bake oven" means a device which uses heat to dry or cure coatings.

(d) "Electrodeposition (EDP)" means a method of applying prime coat. The automobile or light-duty truck body is submerged in a tank filled with coating material, and an electrical field is used to deposit the material on the body.

(e) "Electrostatic spray application" means a spray application method that uses an electrical potential to increase the transfer efficiency of the coating solids. Electrostatic spray application can be used for prime coat, guide coat, or topcoat operations.

(f) "Flash-off area" means the structure on automobile and light-duty truck assembly lines between the coating application system (EDP tank or spray booth) and the bake oven.

(g) "Guide coat operation" means the guide coat spray booth, flash-off area and bake oven(s) which are used to apply and dry or cure a surface coating on automobile and light-duty truck bodies between the prime coat and topcoat operation.

(h) "Light-duty truck" means any motor vehicle rated at 3,850 kilograms (ca. 8,500 pounds) gross vehicle weight or less designed mainly to transport property.

(i) "Prime coat operation" means the prime coat application system (spray booth or dip tank), flash-off area, and bake oven(s) which are used to apply and dry or cure the initial coat on the surface of automobile or light-duty truck bodies.

(j) "Spray application" means a method of applying coatings by atomizing the coating material and directing this atomized spray toward the part to be coated. Spray applications can be used for prime coat, guide coat, and topcoat operations.

(k) "Spray booth" means a structure housing or manual spray application equipment where prime coat, guide coat, or topcoat is applied to automobile or light-duty truck bodies.

(l) "Surface coating operation" means any prime coat, guide coat, or topcoat operation on an automobile or light-duty truck surface coating line.

(m) "Topcoat operation" means the topcoat spray booth(s), flash-off area(s), and bake oven(s) which are used to apply and dry or cure the final coating(s) on automobile and light-duty truck bodies (i.e., those which give an automobile or light-duty truck body its color and surface appearance).

(n) "Transfer efficiency" means the fraction of the total applied coating solids which remains on the part.

(o) "Volatile organic compound" (VOC) means any organic compound which is measured by Method 24 (Candidate 1 or Candidate 2) and Method 25.

(p) "VOC emissions" means the mass of volatile organic compounds, expressed as kilograms of carbon per liter of applied coating solids, emitted from a surface coating operation.

(q) "VOC content" means the volatile organic compound content, in kilograms of carbon per liter of coating solids, of a coating material used in spray applications or coating make-up stream to an EDP tank.

§ 60.392 Standards for volatile organic compounds.

After the performance test required by § 60.8 has been completed, no owner or operator subject to the provisions of this subpart shall discharge or cause of the discharge into the atmosphere of VOC emissions which exceed the following limits:

(a) 0.10 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from each prime coat operation.

(b) 0.84 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from each guide coat operation.

(c) 0.84 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from each topcoat operation.

§ 60.393 Monitoring of operations.

(a) Any owner or operator subject to the provisions of this subpart shall—(1) Install, calibrate, operate, and maintain a monitoring device which records the combustion temperature of any effluent gases which are emitted from any surface coating operation and which are incinerated to comply with § 60.392. The manufacturer must certify that the monitoring device is accurate to within ±2°C (±3.6°F).

(2) Determine the weighted average VOC content of the coating materials used in any EDP prime coat operation whenever a change occurs in the composition of any of these coating materials. The owner or operator shall compute the weighted average by the following equation:

$$C = \frac{\sum_{i=1}^{n} CS_i \times VOLS_i \times SC_i}{\sum_{i=1}^{n} VOLS_i \times SC_i}$$

where:

C = the weighted averaged VOC content of all the coating materials used in an EDP system.

CS_i = the VOC content of the material in each coating makeup stream.

$VOLS_i$ = the volume (cubic meters) of each makeup stream added to the EDP tank during the previous month.

SC_i = the solid content of the material in each coating makeup stream expressed as a volume fraction.

n = the number of makeup streams.

(3) Determine the average VOC content of the coating materials in any surface coating operation which uses spray application whenever a change occurs in the composition of any of these coating materials. The owner or operator shall determine and record the arithmetic average of the VOC content of all coating materials in a coating operation which uses more than one coating material.

(b) Any owner or operator subject to the provisions of this subpart shall report for each calendar quarter all measurement results as follows:

(1) Where compliance with § 60.392 is achieved without the use of add-on control devices, any month during which—

(i) The weighted average VOC content of the makeup materials used in any prime coat operation employing EDP exceeds the most recent value which demonstrated compliance with § 60.392(a) by the performance test required in § 60.8.

(ii) The arithmetic average VOC content of the coating materials used in any surface coating operation employing spray application exceeds the most recent value which demonstrated compliance with § 60.392 by the performance test required in § 60.8.

(2) Where compliance with § 60.392 is achieved by the use of incineration, all periods in excess of 5 minutes during which the temperature in any incinerator used to control the emission from a surface coating operation remains below the most recent level which demonstrated compliance with § 60.392 by the performance tests required in § 60.8. The report required under § 60.7(c) shall identify each such occurrence and its duration.

(3) The reporting requirements in this regulation will automatically expire five years from the date of promulgation unless EPA takes affirmative action to extend them.

§ 60.394 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with § 60.392 as follows:

(1) The owner or operator shall use Reference Method 24 (Candidate 1 or Candidate 2) to measure the VOC content of every coating or makeup material used in each surface coating operation of an automobile or light-duty truck surface coating line. The coating sample shall be a 1 liter sample taken at a point where the sample will be representative of the coating material as applied to the vehicle surface. The 1 liter sample shall be divided into three aliquots for triplicate determinations by Method 24 (Candidate 1 or Candidate 2).

(2) The owner or operator shall compute the arithmetic average VOC content of all coating materials used in each surface coating operation that uses spray application.

(3) The owner or operator shall use the calculation procedures given in § 60.393(a)(2) to compute the weighted average VOC content of all makeup materials added to an EDP tank during a selected one month period for each prime coat operation that uses EDP.

(4) The owner or operator shall determine the VOC emissions by the equation:

$$E = \frac{C}{TE}$$

where:

E = the VOC emissions.

C = the average VOC content of all the coating or makeup materials used in that operation. The owner or operator shall use an arithmetic average for systems using spray application and a weighted average for systems using EDP.

TE = the appropriate transfer efficiency as determined in paragraph (a)(5) of this section.

(5) The owner or operator shall select the appropriate transfer efficiency from the following table for each surface coating operation.

Application method	Transfer efficiency (TE)
Air Atomized Spray	0.40
Manual Electrostatic Spray	0.75
Automatic Electrostatic Spray	0.95
Electrodeposition	1.00

If the owner or operator can justify to the Administrator's satisfaction that other values for transfer efficiencies are appropriate, the Administrator will approve their use on a case-by-case basis. Where more than one application method is used on an individual surface coating operation, the owner or operator shall perform an analysis to determine the relative volume of solids coating materials applied by each method. The owner or operator shall use these relative volumes of solids to compute a weighted average transfer efficiency for the operation. The Administrator will review and approve this analysis on a case-by-case basis.

(b) For each surface coating operation which cannot achieve compliance with § 60.392 without the use of add-on control devices, the owner or operator shall use the following procedures to determine that the emission reduction efficiency of the control device(s) is sufficient to achieve compliance with § 60.392:

(1) The owner or operator shall compute the emission reduction efficiency required for each surface coating operation by the following equation:

$$ER = \frac{E - EL}{E} \times 100$$

where:

ER = the required emission reduction efficiency (in percent) for the applicable surface coating operation to achieve compliance with § 60.392.

E = the VOC emissions from the applicable surface coating operation.

EL = the numerical VOC emission limit in § 60.392 for the applicable surface coating operation.

(2) The owner or operator shall determine the emission reduction efficiency achieved by the control device(s) on each applicable surface coating operation as follows:

(i) The owner or operator shall use Reference Method 25 to determine the

VOC concentration in the effluent gas before and after the emission control device for each stack that is equipped with an emission control device. The owner or operator shall use Reference Method 2 to determine the volumetric flowrate of the effluent gas before and after the emission control device on each stack. The Administrator will approve testing of representative stacks, on a case-by-case basis, if the owner or operator can show to the Administrator's satisfaction that testing of representative stacks yields results comparable to those that would be obtained by testing all stacks.

(ii) For Method 25, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.003 dscm (0.106 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(iii) The owner or operator shall determine the efficiency of each emission control device by the following equation:

$$EFF = \frac{(CB \times VOLB) - (CA \times VOLA)}{(CB \times VOLB)} \times 100$$

where:

EFF = the emission control device efficiency, in percent.
CB = the concentration of VOC in the effluent gas before the emission control device, in parts per million by volume.
CA = the concentration of VOC in the effluent gas after the emission control device, in parts per million by volume.
VOLA = the volumetric flow rate of the effluent gas after the emission control device, in dry standard cubic meters per second.
VOLB = the volumetric flow rate of the effluent gas before the emission control device, in dry standard cubic meters per second.

If an emission control device controls the emissions from more than one stack, the owner or operator shall measure CB and VOLB at a location between the manifold that receives all the exhausts from the applicable surface coating operation and the control device. If a manifold is not used, the product CB×VOLB shall be replaced by the sum of the individual products for each stack on the applicable surface coating operation controlled by this device.

(iv) The owner or operator shall determine the fraction of the total VOC discharged from an applicable surface coating operation which enters each emission control device on that operation by the following equation:

$$F_i = \frac{CB_i \times VOLB_i}{\sum_{k=1}^{n} (CB_k \times VOLB_k)}$$

where:

F_i = the fraction of the total VOC discharged from the applicable surface coating operation which enters the emission control device.
CB_i = the value of CB for stack (k) on the applicable surface coating operation.
CB_k = the value of CB for each stack (k) on the applicable surface coating operation.
$VOLB_i$ = the value of VOLB for each emission control device (i).
$VOLB_k$ = the value of VOLB for each stack (k) on the applicable surface coating operation.
n = the number of stacks on the applicable surface coating operation.

The owner or operator shall use the procedures contained in clause (ii) of this subparagraph for any emission control device (i) that controls the emissions from more than one stack.

(v) The owner or operator shall determine the emission reduction efficiency achieved by the control device(s) on the applicable surface coating operation using the equation:

$$EA = \sum_{i=1}^{m} (F_i \times EFF_i)$$

where:

EA = the emission reduction efficiency achieved, in percent.
EFF_i = the emission reduction efficiency (in percent) of each control device on the applicable surface coating operation.
m = the number of control devices on the applicable surface coating operation.

(3) If EA is greater than or equal to ER, the applicable surface coating operation will be in compliance with § 60.392.

§ 60.395 Modifications.

(a) The following physical or operational changes are not, by themselves, considered modifications of existing facilities:

(1) Changes as a result of model year changeovers or switches to larger cars.

(2) Changes in the application of the coatings to increase paint film thickness.

Appendix A—Reference Methods

3. Method 24 (Candidate 1), Method 24 (Candidate 2), and Method 25 are added to Appendix A as follows:

* * * * *

Method 24 (Candidate 1)—Determination of Volatile Content (as Carbon) of Paint, Varnish, Lacquer, or Related Products

1. Applicability and Principle

1.1 *Applicability.* This method is applicable for the determination of volatile content (as carbon) of paint, varnish, lacquer, and related products listed in Section 2.

1.2 *Principle.* The weight of volatile carbon per unit volume of solids is calculated for paint, varnish, lacquer, or related surface coating after using standard methods to determine the volatile matter content, density of the coating, density of the solvent, and using the oxidation-nondispersive infrared (NDIR) analysis for the carbon content.

2. Classification of Surface Coating

For the purpose of this method, the applicable surface coatings are divided into two classes. They are:

2.1 *Class I: General Solvent-Type Paints and Water Thinned Paints.* This class includes white linseed oil outside paint, white soya and phthalic alkyd enamel, white linseed o-phthalic alkyd enamel, red lead primer, zinc chromate primer, flat white inside enamel, white epoxy enamel, white vinyl toluene, modified alkyd, white amino modified baking enamel, and other solvent-type paints not included in class II. It also includes emulsion or latex paints and colored enamels.

2.2 *Class II: Varnishes and Lacquers.* This class includes clear and pigmented lacquers and varnishes.

3. Applicable Standard Methods

Use the apparatus, reagents, and procedures specified in the standard methods below:

3.1 *ASTM D 1644–59 Method A:* Standard Methods of test for Non-volatile Contents of Varnishes. Do not use Method B.

3.2 *ASTM D 1475–60.* Standard Method of Test for Density of Paint, Lacquer, and Related Products.

3.3 *ASTM D 2369–73:* Standard Method of Test for Volatile Content of Paints.

3.4 *ASTM D 3272–76:* Standard Recommended Practice for Vacuum Distillation of Solvents from Solvent-Base Paints for Analysis.

4. Apparatus (Oxidation/NDIR Procedure)

4.1 *Electric Furnace.* Capable of maintaining a temperature of 800±50° C.

4.2 *Combustion Chamber.* Stainless steel tubing, 13 mm (½ in.) internal diameter and 46 cm (18 in.) in length. Pack the tube loosely with 3 mm (⅛ in.) alumina pellets coated with 5 percent palladium. Place plugs of stainless steel wool at either end. Other catalytic systems which can demonstrate 95 percent efficiency as described in Section 6.5.4 are considered equivalent.

4.3 *Septum.* Teflon [1]-coated rubber septum.

4.4 *Condenser.* Ice bath condenser.

4.5 *Analyzer.* Nondispersive infrared analyzer (NDIR) to measure CO_2 TO WITHIN ◊5 PERCENT OF THE CALIBRATION GAS CONCENTRATION.

4.6 *Recorder.* Capable of matching the output of the NDIR.

4.7 *Collection Tank.* A collection tank of at least 6 liters in volume. See procedure in Section 6.5.1 for calibrating the volume of the tank. The tank should be capable of

[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

withstanding a pressure of 2000 mm (80 in.) Hg (gauge).

4.8 Pressure Gauge for Collection Tank. Capable of measuring positive pressure to 1100 mm (42 in.) Hg and vacuum pressure to 700±5 mm (28±0.25 in.) Hg.

4.9 Vacuum Pump. Capable of evacuating the collection tank to an absolute pressure of 51 mm (2 in.) Hg.

4.10 Analytical Balance. To measure to within ±0.5 mg.

4.11 Syringes. 100±1.0 μl, 500±1.0 μl, and 1000±5 μl syringe, with needles long enough to inject sample directly into the carrier gas stream.

4.12 Mixer. Vortex-mixer to ensure homogeneous mixing of solvent.

4.13 Flow Regulators. Rotameters, or equivalent, to measure to 500 cc/min in flow-rate.

4.14 Temperature Gauge. A thermometer graduated in 0.1° C, with range from 0° C to 100° C.

4.15 Tank Calibration Equipment. A balance to weigh collection tank to ±30 g or a graduated glass cylinder to measure tank volume within ±30 ml.

5. Reagents (Oxidation/NDIR Procedure)

5.1 Calibration Gases.

5.1.1 Zero Gas. Nitrogen.

5.1.2 CO_2 Gas. A range of concentration to allow at least a 3-point calibration of each measuring range of the instrument.

5.1.3 Carrier Gas. Air containing less than 1 ppm hydrocarbon as carbon, as certified by the manufacturer.

5.2 Catalyst. Alumina (3 mm pellets) coated with 5 percent palladium, or equivalent (commercially available).

5.3 Acetone. Reagent grade.

5.4 Nitric Acid Solution. Dilute 70 percent nitric acid 1:1 by volume with distilled water.

5.5 1-Butanol. Ninety-nine molecular percent pure.

5.6 Methane Gas. 0.5 percent methane in air.

6. Procedure

6.1 Classification of Samples. Assign the coating to one of the two classes discussed in Section 2 above. Assign any coating not clearly belonging to Class II to Class I.

6.2 Volatile Content. Use one of the following methods to determine the volatile content according to the class of coating.

6.2.1 Class I. Use the Procedure in ASTM D 2369–73. Record the following information:

W_1=Weight of dish and sample, g.
W_2=Weight of dish and sample after heating, g.
S=Sample weight, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction of volatile matter W for each analysis as follows:

$$W = \frac{W_1 - W_2}{S}$$

Report the arithmetic average weight fraction $\bar{W}$ of the three determinations.

6.2.2 Class II. Use the procedure in ASTM D 1644–59 Method A; record the following information:

A=Weight of dish, g.
B=Weight of sample used, g.
C=Weight of dish and sample after heating, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction W of volatile content for each analysis as follows:

$$W = \frac{(A + B - C)}{B}$$

Report the arithmetic average weight fraction $\bar{W}$ of three determinations.

6.3 Coating Density. Determine the density D_m (in g/cm³) of the paint, varnish, lacquer, or related product of either class according to the procedure outlined in ASTM D 1475–60. Make a total of three determinations for each coating. Report the density $\bar{D}_m$ as the arithmetic average of the three determinations.

6.4 Solvent Density.

6.4.1 Perform the solvent extraction according to the procedure outlined in ASTM D 3272–76. For aqueous paint, use a collection-tube in an ice-bath prior to the collection-tube in the acetone and dry-ice mixture to prevent water from freezing in the collection-tube. Combine the contents of both tubes before analysis. If excessive foaming occurs during distillation, discard the sample, and repeat with a new sample treated with an anti-foam spray (e.g. Dow Corning's "Anti-foam A Spray) before distillation. Anti-foam spray must be nonorganic and nonflammable. Use spray sparingly.

6.4.2 Determine the density D_s (in g/cm³) of the solvent according to the procedure outlined in ASTM D 1475–60. Make a total of three determinations for the solvent, and report the average density $\bar{D}_s$ as the arithmetic average of the three determinations.

6.5 Carbon Content of the Solvent. Analyze the solvent within 24 hours after distillation; keep it under refrigeration when not in use. To determine the carbon content, follow the procedure below:

6.5.1 Clean and calibrate the collection tank as follows: Rinse the inside of the tank once with acetone, twice with tap water, thrice with the nitric acid solution, and twice with tap water. Weigh the tank when empty and when full of water. Measure the temperature of the water, and calculate the volume as follows:

$$V = \frac{W_f - W_e}{D_t}$$

Where:

t=Temperature of the water, °C (°F).
V=Volume of the tank, ml.
W_e=Weight of the empty tank, g.
W_f=Weight of the full tank, g.
D_t=Density of water at temperature t, g/ml.

Alternatively, measure the volume of water necessary to fill the tank. The volume of the tank connections and pressure gauge are negligible for a tank volume of at least 6 liters.

6.5.2 Calibrate the NDIR according to the manufacturer's instruction. Use at least a 3-point calibration. Introduce the CO_2 calibration gas through the analysis line.

6.5.3 Assemble the oxidation system as shown in Figure 1. Heat the catalyst until the temperature reaches equilibrium at 800 ±50° C. Add ice to the condenser and remove excess water to maintain the temperature at 0° C.

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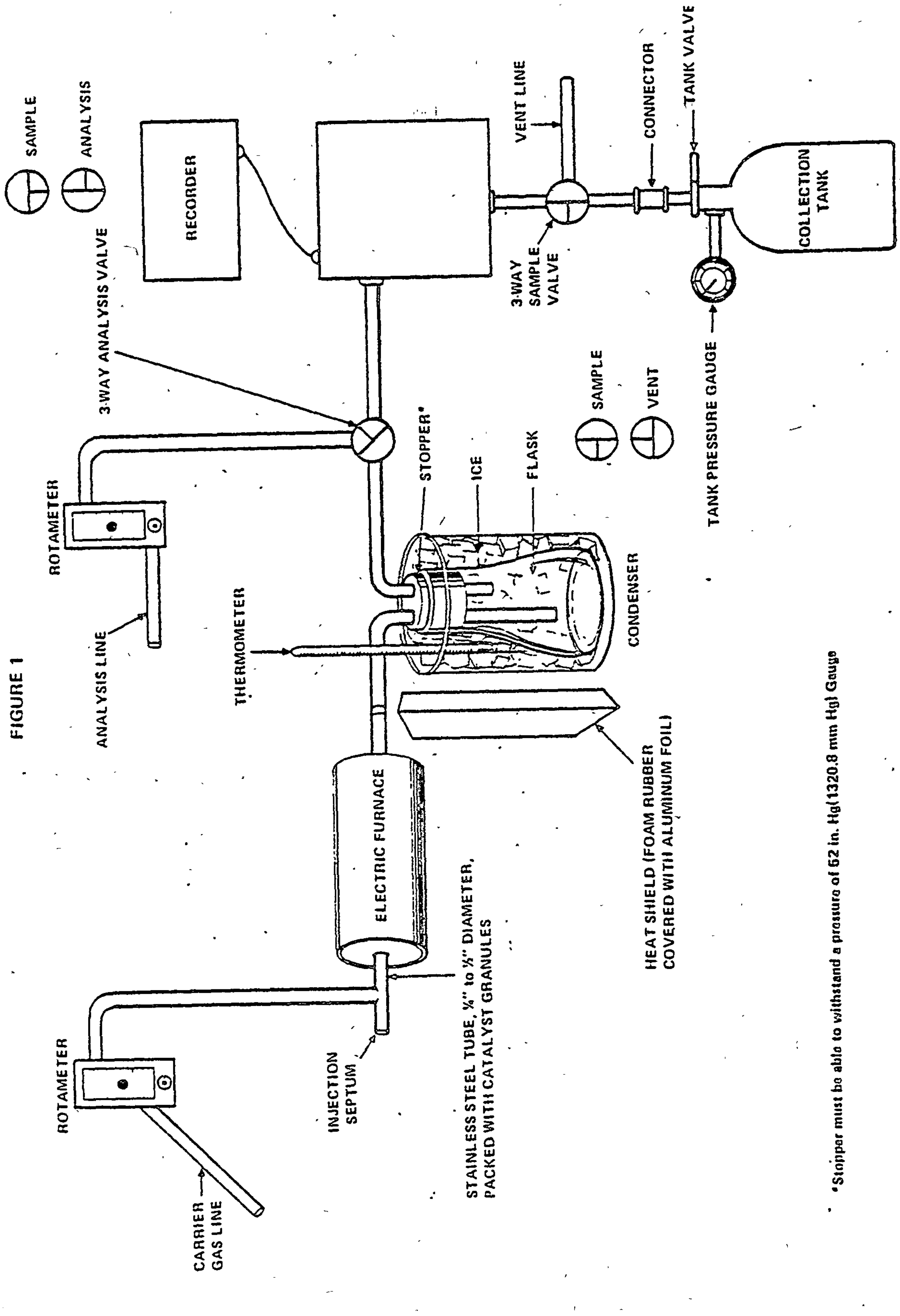
FIGURE 1



*Stopper must be able to withstand a pressure of 52 in. Hg (1320.8 mm Hg) Gauge

6.5.4 Determination of Conversion Efficiency. Pass 0.5 percent methane gas in air through carrier gas line; 0.5 percent CO_2 should be generated within ±5 percent error. Using a 100 μl sample of l-butanol, follow the procedure in 6.5.5 to 6.5.13. Calculate the theoretical CO_2 volume percent as in Section 7.3. This value should equal the value as measured by the NDIR, within ±5 percent error. If conversion efficiency is 100 ±5 percent, analyze the solvent extracted from the paint according to procedure in Sections 6.5.5 to 6.5.14.

6.5.5 Purge the collection tank twice with N_2, then evacuate the tank to at least 50.8 mm (2 in.) Hg absolute pressure. Connect the cylinder to the collection line.

6.5.6 Mix the solvent sample thoroughly on a vortex-mixer. Then, draw a sample (0.100 to 0.300 ml) into the syringe. Record the volume of sample used.

6.5.7 Turn analysis valve to "sample" position, and turn the sample valve to "vent" position. Then turn on the carrier gas at a rate of 500 cc/min to flush the system for 2 minutes.

6.5.8 With gas flowing at 500 cc/min (maintain this rate throughout the test procedure), turn sample valve to "sample" position. Open the tank valve and inject the sample into the gas stream through the injection septum. Continue to draw the sample into the tank until the NDIR reads zero. (Note.— On replicate samples, a decrease in peak value indicates that the catalyst or sample has deteriorated, assuming that other factors, such as leaks, cell contamination, mechanical defects of the instruments, etc., have not occurred.)

6.5.9 At completion of collection, close the tank valve, and turn sample valve to "vent" position. Let the carrier gas flush the system for 2 minutes, then turn off the carrier gas.

6.5.10 Disconnect the tank and pressurize it with N_2 to about 1016 mm (40 in.) Hg gauge pressure. Record the final tank pressure after pressurization, the atmospheric pressure, and the room temperature.

6.5.11 Connect the tank to the analysis line and turn the analysis valve to "analysis" position.

6.5.12 Pass the CO_2 sample gas at the same rate as the calibration gas. Keep the rate constant by adjusting the rotameter as tank pressure falls.

6.5.13 Record the CO_2 concentration when the peak value is reached. This peak value will remain constant as long as the sample gas continues to flow at a constant rate.

6.5.14 Repeat steps 6.5.5 through 6.5.13 until three consecutive results are obtained which differ from one another in value by no more than ±5 percent. At the end of the third test, check the catalyst function by passing the collected sample gas through the catalyst and into the NDIR. No increase in concentration value should occur. If the concentration is higher, invalidate the test series, replace the catalyst and repeat the test.

6.5.15 Report the results as an arithmetic average of the three determinations.

7. Calculations. Carry out the calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after decimal calculation.

7.1 Nomenclature.

C_c=Volatile matter content as carbon per unit volume of paint solids, g/l (lb/gal).

D_b=Density of l-Butanol, g/cm³.

D_m=Average coating density, g/cm³ (See Section 6.3).

D_s=Average solvent density, g/cm³ (See Section 6.4).

L_b=Volume of l-Butanol used in the test, cm³.

L_s=Volume of paint solvent used in the test, cm³.

74.12=Molecular weight of l-Butanol.

M_c=Mass of carbon, g.

4=Number of carbon atoms in l-Butanol.

P_{std}=Absolute standard pressure, 760 mm Hg (29.92 in. Hg).

P_f=Absolute final tank pressure after pressurization, mm Hg (in. Hg).

T_{std}=Absolute standard temperature, 293° K (528° R).

T_t=Absolute tank temperature, °K (°R).

%Solv.=Volume percent of solvent in paint coating.

V_{CO_2}=Volume of CO_2 in liters, at standard temperature and pressure.

V_{gs}=Total gas volume, corrected to standard conditions, in liters.

V_{pc}=Volume percent of CO_2.

V_t=Volume of tank, liters.

W=Weight fraction of volatile matter content.

7.2 Total Gas Volume, Corrected to Standard Conditions.

$$V_{gs} = \frac{T_{std}}{P_{std}} \frac{P_f}{T_t} V_t = K_1 \frac{P_f}{T_t} V_t \qquad \text{Equation 1}$$

Where:

K_1=17.65 for English units.

K_1=0.3855 for Metric units.

7.3 Volume Percent of CO_2 From l-Butanol:

$$V_{pc} = \frac{1.298\ L_b\ D_b}{V_{gs}} \qquad \text{Equation 2}$$

7.4 Mass of Carbon

$$M_c = V_{pc}\ V_{gs}\ \frac{12.0}{24.056}\ \frac{1}{100} \qquad \text{Equation 3}$$

7.5 Percent Volume Solvent in Paint.

$$\%\text{Solv.} = \bar{W}\ \frac{\bar{D}_m}{\bar{D}_s}\ (100) \qquad \text{Equation 4}$$

7.6 Volatile Matter Content as Carbon.

$$C_c = K_2\ \frac{M_c}{L_s}\ \frac{\%\text{Solv.}}{100 - \%\text{Solv.}} \qquad \text{Equation 5}$$

Where:

K_2=8.3445 for English units.

K_2=1000 for Metric units.

8. Bibliography.

8.1 Standard Methods of Test for Nonvolatile Content of Varnishes. In: 1974 Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania, ASTM Designation D 1644–59. 1974. p. 285–286.

8.2 Standard Method of Test for Volatile Content of Paints. In: 1978 Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania, ASTM Designation D 2369–73. 1978. p. 431–432.

8.3 Standard Method of Test for Density of Paint, Varnish, Lacquer, and Related Products. In: 1974 Book of ASTM Standards, Part 25. Philadelphia, Pennsylvania, ASTM Designation D 1476–60. 1974. p. 231–233.

8.4 Standard Recommended Practice for Vacuum Distillation of Solvents from Solvent-Base Paints for Analysis. In: 1978 Annual Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania, ASTM Designation D 3272076. 1978. p. 612–614.

8.5 Salo, Albert E., William L. Oaks, and Robert D. MacPhee. Total Combustion Analysis. Air Pollution Control District- County of Los Angeles. August 1974.

Method 24 (Candidate 2)—Determination of Volatile Organic Compound Content (as Mass) of Paint, Varnish, Lacquer, or Related Products

1. *Applicability and Principle.*

1.1 Applicability. This method applies to the determination of volatile organic compound content (as mass) of paint, varnish, lacquer, and related products listed in Section 2.

1.2 Principle. Standard methods are used to determine the volatile matter content, density of the coating, volume of solid, and water content of the paint, varnish, lacquer, and related surface coating. From this information, the mass of volatile organic compounds per unit volume of solids is calculated.

2. *Classification of Surface Coating.* For the purpose of this method, the applicable surface coatings are divided into three classes. They are:

2.1 Class I: General Solvent Reducible Paints. This class includes white linseed oil outside paint, white soya and phthalic alkyd enamel, white linseed o-phthalic alkyd enamel, red lead primer, zinc chromate primer, flat white inside enamel, white epoxy enamel, white vinyl toluene, modified alkyd, white amino modified baking enamel, and other solvent-type paints not included in Class II.

2.2 Class II: Varnishes and Lacquers. This class includes clear and pigmented lacquers and varnishes.

2.3 Class III. This class includes all water reducible paints.

3. *Applicable Standard Methods.* Use the apparatus, reagents, and procedures specified in the standard method below:

3.1 ASTM D 1644–75 Method A: Standard Method of Test for Non-volatile Contents of Varnishes. Do not use Method B.

3.2 ASTM D 1475–60. Standard Method of Test for Density of Paint, Lacquer, and Related Products.

3.3 ASTM D 2369–73. Standard Method of Test for Volatile Content of Paints.

3.4 ASTM D 2697–73. Standard Method of Test for Volume Non-volatile Matter in Clear or Pigmented Coatings.

3.5 ASTM D 3792. Standard Method of Test for Water in Water Reducible Paint by Direct Injection into a Gas Chromatograph.

3.6 ASTM Draft Method of Test for Water in Paint or Related Coatings by the Karl Fischer Titration Method.

4. *Procedure.*

4.1 Classification of Samples. Assign the coating to one of the three classes discussed in Section 2 above. Assign any coating not clearly belonging to Class II or III to Class I.

4.2 Non-Aqueous Volatile Content. Use one of the following methods to determine the non-aqueous volatile content according to the class of coating.

4.2.1 Class I. Use the procedure in ASTM D 2369–73; record the following information:

W_1=Weight of dish and sample, g.
W_2=Weight of dish and sample after heating g.
S=Sample of weight, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction of non-aqueous volatile matter W_v for each analysis as follows:

$$W_v = \frac{W_1 - W_2}{S}$$

Report the arithmetic average weight fraction $\bar{W}_v$ of the three determinations.

4.2.2 Class II. Use the procedure in ASTM D 1644–75 Method A; record the following information:

A=Weight of dish, g.
B=Weight of sample used, g.
C=Weight of dish and sample after heating, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction W_v of non-aqueous volatile content for each analysis as follows:

$$W_v = \frac{(A + B - C)}{B}$$

Report the arithmetic average weight fraction $\bar{W}_v$ of the three determinations.

4.2.3 Class III.

4.2.3.1 Water Content. Determine the water content (in % H_2O) of the coating according to either "Provisional Method of Test for Water in Water Reducible Paint by Direct Injection into a Gas Chromatograph" or "Provisional Method of Test for Water in Paint or Related coatings by the Karl Fischer Titration Method." Repeat the procedure for a total of three determinations for each coating. Report the arithmetic average weight percent $\overline{\%}\ H_2O$ of the three determinations.

4.2.3.2 Volatile Content (Including Water). Use the procedure in ASTM D 2369–73; record the following information:

W_1=Weight of dish and sample, g.
W_2=Weight of dish and sample after heating, g.
S=Sample weight, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction of volatile matter as follows:

$$V = \frac{W_1 - W_2}{S}$$

Report the arithmetic average weight fraction $\bar{V}$ of the three determinations.

4.2.3.3 Non-Aqueous Volatile Matter. Calculate the average non-aqueous volatile matter $\bar{W}_v$ as follows:

$$\bar{W}_v = \bar{V} - \frac{\overline{\%\ H_2O}}{100}$$

4.3 Coating Density. Determine the density D_m (in g/cm^3) of the paint, varnish, lacquer, or related product of any class according to the procedure outlined in ASTM D 1475–60. Make a total of three determinations for each coating. Report the density $\bar{D}_m$ as the arithmetic average of the three determinations.

4.4 Non-Volatile Content. Determine the volume fraction of the non-volatile matter of the coating of any class according to the procedure outlined in ASTM D 2697–73. Calculate the volume fraction P_n of non-volatile matter as follows:

$$P_n = \frac{\%\ \text{Volume Nonvolatile Matter}}{100}$$

Make a total of three determinations for each coating. Report the arithmetic average volume fraction $\bar{P}_n$ of the three determinations.

5. *Volatile Organic Compounds Content.* Calculate the volatile organic compound content C_m in terms of mass per volume of solids (g/liter) as follows:

$$C_m = \frac{\bar{W}_v \bar{D}_m}{\bar{P}_n}$$

To convert g/liter to lb/gal, multiply C_m by 8.3455×10^{-3}.

6. *Bibliography.*

6.1 Standard Methods of Test of Nonvolatile Content of Varnishes. In: 1974 Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania, ASTM Designation D 1644–75. 1978. p. 288–289.

6.2 Standard Method of Test for Volatile Content of Paints. In: 1978 Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania, ASTM Designation D 2369–73. 1978. p. 431–432.

6.3 Standard Method of Test for Density of Paint, Varnish, Lacquer, and Related Products. In: 1974 Book of ASTM Standards, Part 25. Philadelphia, Pennsylvania, ASTM Designation D 1476–60. 1974. p. 231–233.

6.4 Standard Method of Test for Water in Water Reducible Paint by Direct Injection into a Gas Chromatograph. Available from: Chairman, Committee D–1 on Paint and Related Coatings and Materials, American Society for Testing and Materials, 1916 Race St., Philadelphia, PA 19103. ASTM Designation D 3792.

6.5 Draft method of Test for Water in Paint or Related Coatings by the Karl Fischer Titration Method. Available from: Chairman, Committee D–1 on Paint and Related Coatings and Materials, American Society for Testing and Materials, 1916 Race St., Philadelphia, PA 19103.

Method 25—Determination of Total Gaseous Nonmethane Organic Emissions as Carbon: Manual Sampling and Analysis Procedure

1. Principle and Applicability.

1.1 Principle. An emission sample is anisokinetically drawn from the stack through a chilled condensate trap by means of an evacuated gas collection tank. Total gaseous nonmethane organics (TGNMO) are determined by combining the analytical results obtained from independent analyses of the condensate trap and evacuated tank fractions. After sampling is completed, the organic contents of the condensate trap are oxidized to carbon dioxide which is quantitatively collected in an evacuated vessel; a portion of the carbon dioxide is reduced to methane and measured by a flame ionization detector (FID). A portion of the sample collected in the gas sampling tank is injected into a gas chromatographic (GC) column to achieve separation of the nonmethane organics from carbon monoxide, carbon dioxide and methane; the nonmethane organics are oxidized to carbon dioxide, reduced to methane, and measured by a FID.

1.2 Applicability. This method is applicable to the measurement of total gaseous nonmethane organics in source emissions.

2. Apparatus.

2.1 General. TGNMO sampling equipment can be constructed by a laboratory from commercially available components and components fabricated in a machine shop. The primary components of the sampling system are a condensate trap, flow control system, and gas sampling tank (Figure 1). The analytical system consists of two major subsystems; an oxidation system for recovery of the sample from the condensate trap and a TGNMO analyzer. The TGNMO analyzer is a FID preceded by a reduction catalyst, oxidation catalyst, and GC column with backflush capability (Figures 2 and 3). The system for the removal and conditioning of the organics captured in the condensate trap consists of a heat source, oxidation catalyst, nondispersive infrared (NDIR) analyzer and an intermediate gas collection tank (Figure 4).

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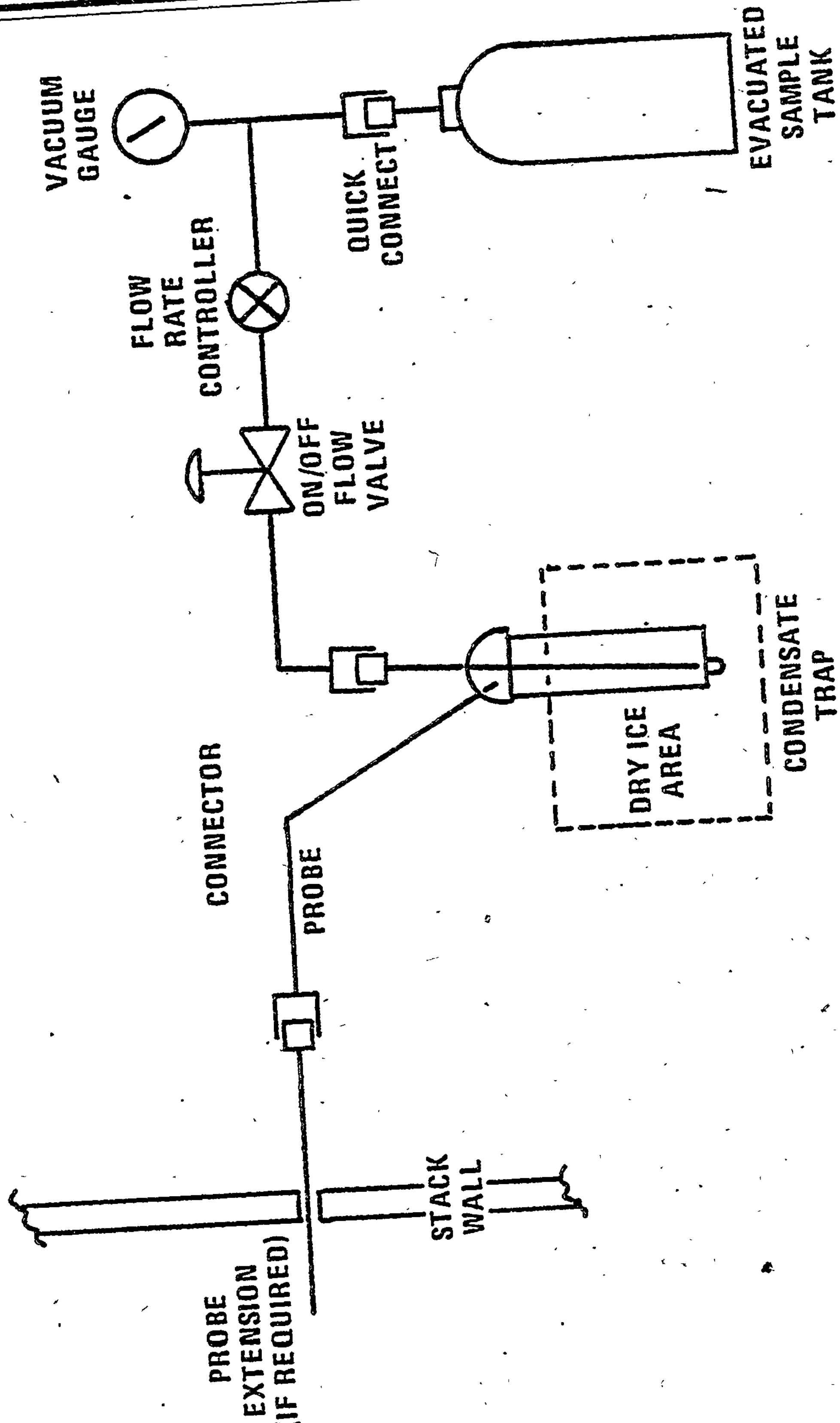

Figure 1. Sampling apparatus.

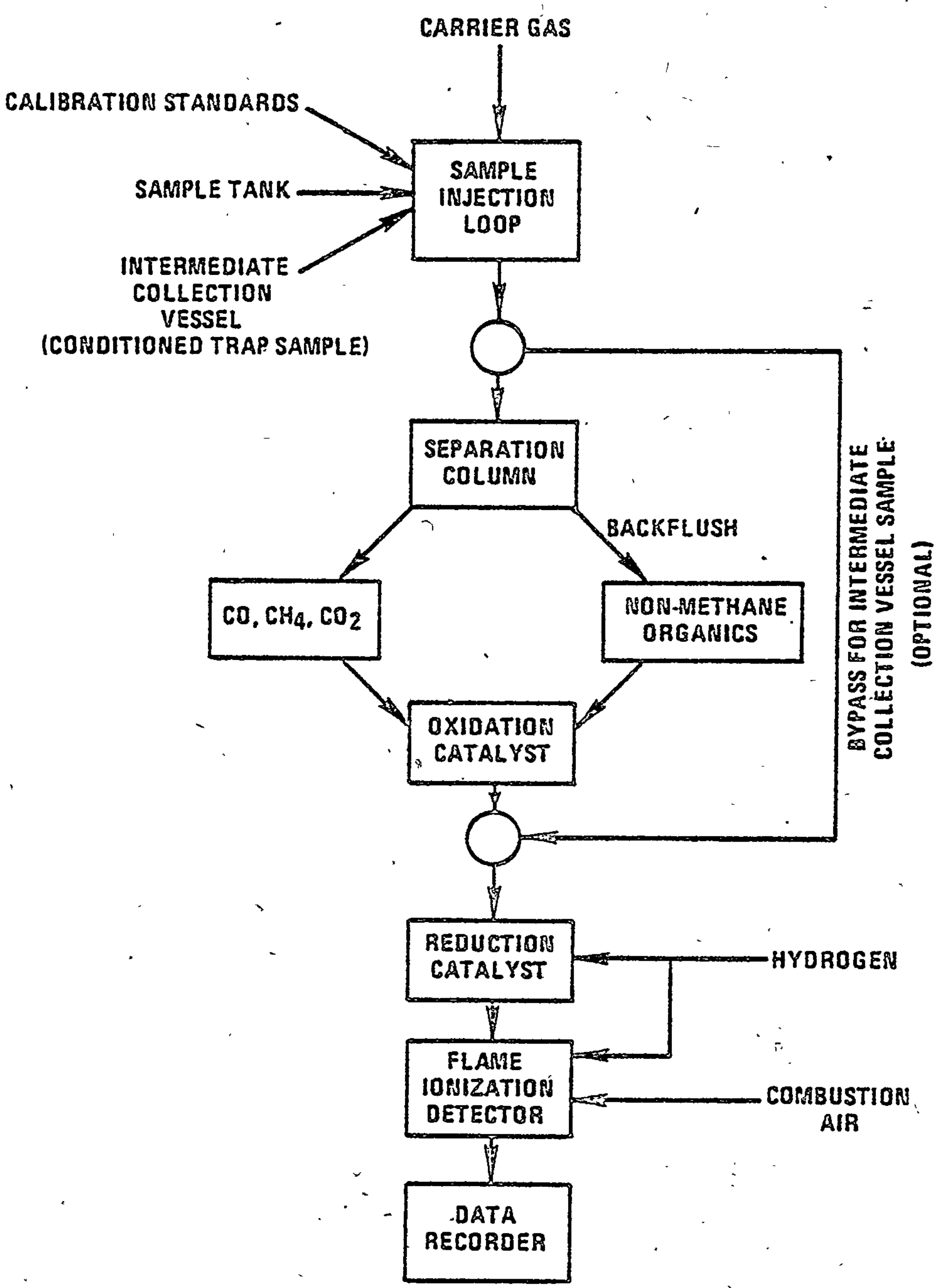

Figure 2. Simplified schematic of total gaseous non-methane organic (TGNMO) analyzer.

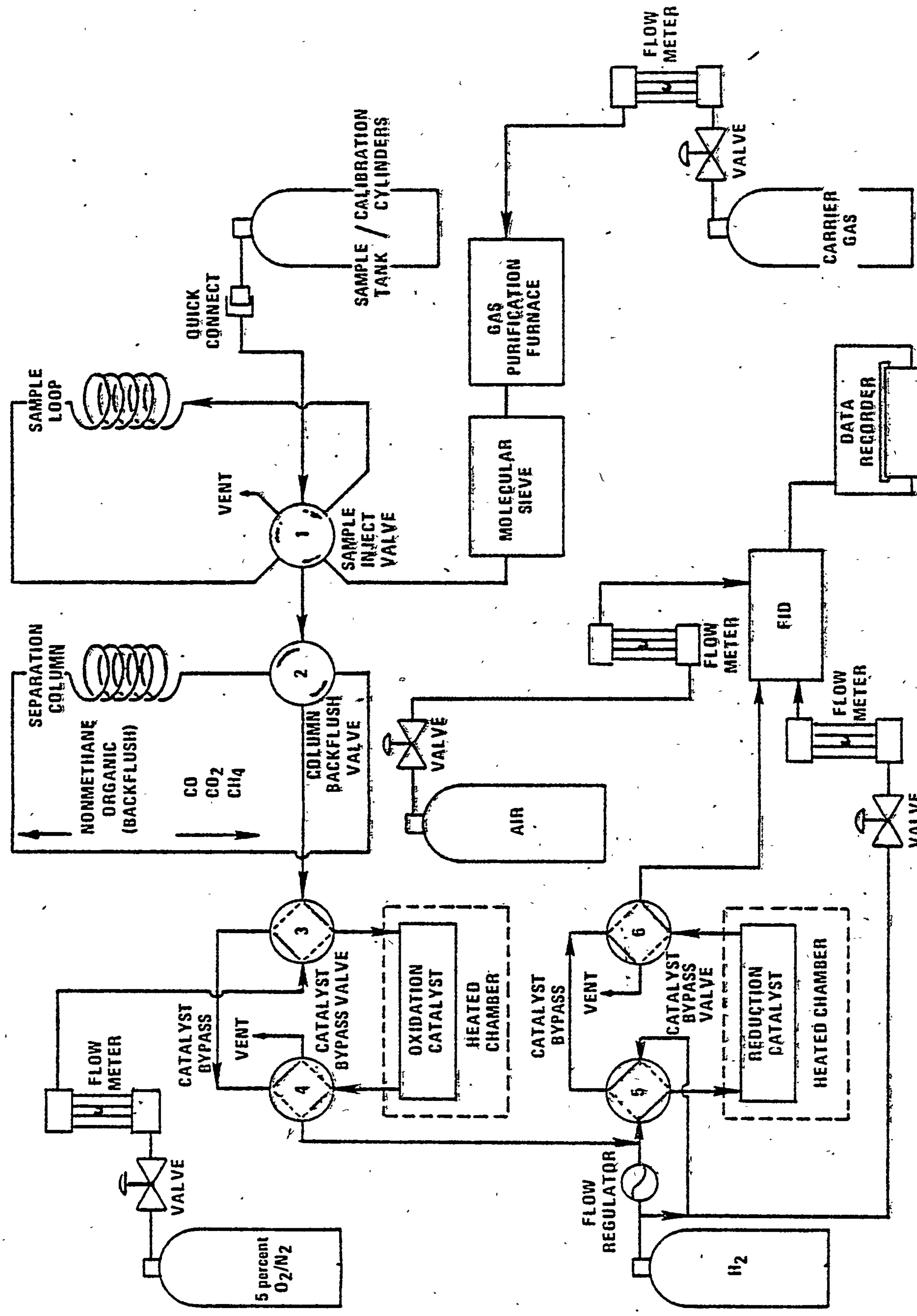

Figure 3. Total gaseous nonmethane organic (TGNMO) analyzer.

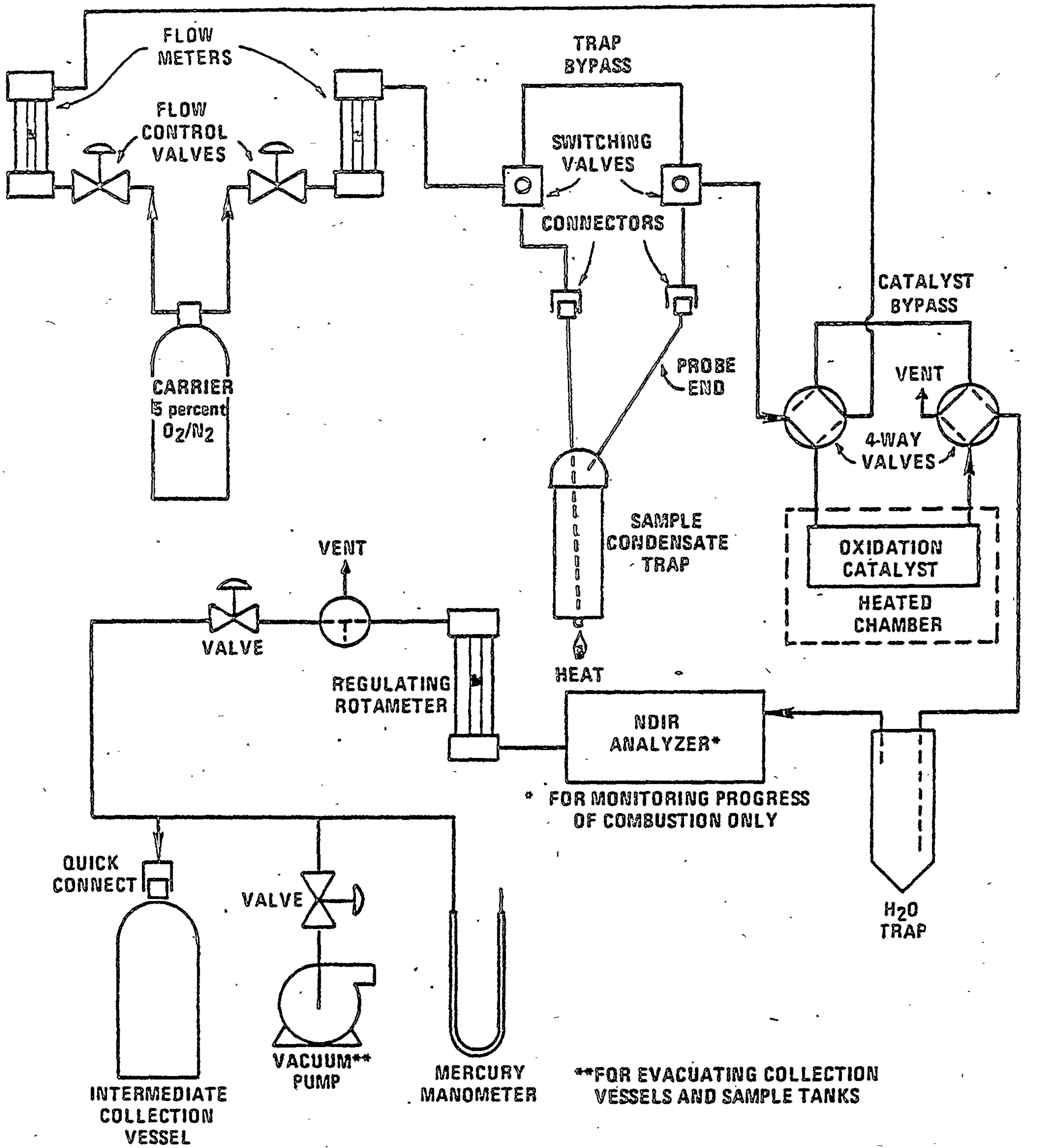

Figure 4. Condensate recovery and conditioning apparatus.

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2.2 Sampling.

2.2.1 Probe. 1/8" stainless steel tubing.

2.2.2 Condensate Trap. The condensate trap shall be constructed of 316 stainless steel; construction details of a suitable trap are shown in Figure 5.

2.2.3 Flow Shut-off Valve. Stainless steel control valve for starting and stopping sample flow.

2.2.4 Flow Control System. Any system capable of maintaining the sampling rate to within ±10 percent of the selected flow rate (50—100 cc/min. range).

2.2.5 Vacuum Gauge. Vacuum gauge calibrated in mm Hg. for monitoring the vacuum of the evacuated sampling tank during leak checks and sampling.

2.2.6 Gas Collection Tank. Stainless steel or aluminum tank with a volume of 4 to 8 liters. The tank is fitted with a stainless steel female quick connect for assembly to the sampling train and analytical system.

2.2.7 Mercury manometer. U-tube mercury manometer capable of measureing pressure to within 1.0 mm Hg in the 0/900 mm range.

2.2.8 Vacuum Pump. Capable of pulling a vacuum of 700 mm Hg.

2.3 Analysis. For analysis, the following equipment is needed.

2.3.1 Condensate Recovery and Conditioning Apparatus (Figure 4).

2.3.1.1 Heat Source. A heat source sufficient to heat the condensate trap to a temperature just below the point where the trap turns a "cherry red" color is required. An electric muffle-type furnace heated to 600° C is recommended.

2.3.1.2 Oxidizing Catalyst. Inconel tubing packed with an oxidizing catalyst capable of meeting the catalyst efficiency criteria of this method (Section 4.4.2).

2.3.1.3 Water Trap. Any leak proof moisture trap capable of removing moisture from the gas stream may be used.

2.3.1.4 NDIR Detector. A detector capable of indicating CO_2 concentration in the zero to 5 percent range. This detector is required for monitoring the progress of combustion of the organic compounds from the condensate trap.

2.3.1.5 Pressure Regulator. Stainless steel needle valve required to maintain the NDIR detector cell at a constant pressure.

2.3.1.6 Intermediate Collection Tank. Stainless steel or aluminum collection vessel. Tanks with nominal volumes in the 1 to 4 liter range are recommended. The end of the tank is fitted with a female quick connect.

2.3.2 Total Gaseous Nonmethane Organic (TGNMO) Analyzer. Semi-continuous GC/FID analyzer capable of: (1) separating CO, CO_2, and CH_4 from nonmethane organic compounds, and (2) oxidizing the non-methane organic compounds to CO_2, reducing the CO_2 to methane, and quantifying the methane. The analyzer shall be demonstrated prior to initial use to be capable of proper separation, oxidation, reduction, and measurement. As a minimum, this demonstration shall include measurement of a known TGNMO concentration present in a mixture that also contains CH_4, CO, and CO_2 (see paragraph 4.4.1).

2.3.2.1 The TGNMO analyzer consists of the following major components.

2.3.2.1.1 Oxidation Catalyst. Inconel tubing packed with an oxidation catalyst capable of meeting the catalyst efficiency criteria of paragraph 4.4.1.2.

2.3.2.1.2 Reduction Catalyst. Inconel tubing packed with a reduction catalyst capable of meeting the catalyst efficiency criteria of paragraph 4.4.1.3.

2.3.2.1.3 Separation Column. A gas chromatographic column capable of separating CO, CO_2, and CH_4 from nonmethane organic compounds. The specified column is as follows: 1/8 inch O.D. stainless steel packed with 3 feet of 10 percent methyl silicone, Sp 2100* (or equivalent) on Supelcoport* (or equivalent), 80/100 mesh, followed by 1.5 feet porapak Q* (or equivalent) 60/80 mesh. The inlet side is to the silicone.

Other columns may be used subject to the approval of the Administrator. In any event, proper separation shall be demonstrated according to the procedures of paragraph 4.4.1.4.

2.3.2.1.4 Sample Injection System. A gas chromatographic sample injection valve with sample loop sized to properly interface with the TGNMO system.

2.3.2.1.5 Flame Ionization Detector (FID). A flame ionization detector meeting the following specifications is required:

2.3.2.1.5.1 Linearity. A linearity of ±5 percent of the expected value for each full scale setting up to the maximum percent absolute (methane or carbon equivalent) calibration point is required. The FID shall be demonstrated prior to initial use to meet this specification through a 5-point (minimum) calibration. There shall be at least one calibration point in each of the following ranges: 5–10, 50–100, 500–1,000, 5,000–10,000, and 40,000–100,000 ppm (methane or carbon equivalent). Certification of such demonstration by the manufacturer is acceptable. An additional linearity performance check (see Section 4.4.1.1) must be made before each use (i.e., before each set of samples is analyzed or daily whichever occurs first).

2.3.2.1.5.2 Range. Signal attenuators shall be available so that a minimum signal response of 10 percent of full scale can be produced when analyzing calibration gas or sample.

2.3.2.1.5.3 Sensitivity. The detector sensitivity shall be equal to or better than 2.0 percent of the full scale setting, with a minimum full scale setting of 10 ppm (methane or carbon equivalent).

2.3.2.1.6 Data Recording System. Analog strip chart recorder or digital integration system for permanently recording the analytical results.

2.3.3 Mercury Manometer. U-tube mercury manometer capable of measuring pressure to within 1.0 mm Hg in the 0–900 mm range.

2.3.4 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 1 mm.

2.3.5 Vacuum Pump. Laboratory vacuum pump capable of evacuating the sample tanks to an absolute pressure of 5 mm Hg.

3. Reagents.

3.1 Sampling.

3.1.1 Crushed Dry Ice.

3.2 Analysis.

3.2.1 TGNMO Analyzer.

3.2.1.1 Carrier Gas. Pure helium, containing less than 1 ppm organics.

3.2.1.2 Fuel Gas. Pure Hydrogen, containing less than 1 ppm organics.

3.2.2 Condensate Recovery and Conditioning Apparatus.

3.2.2.1 Carrier Gas. Five percent O_2 in N_2, containing less than 1 ppm organics.

3.3 Calibration. For all calibration gases, the manufacturer must recommend a maximum shelf life for each cylinder so that the gas concentration does not change more than ±5 percent from its certified value. The date of gas cylinder preparation, certified organic concentration and recommended maximum shelf life must be affixed to each cylinder before shipment from the gas manufacturer to the buyer.

3.3.1 TGNMO Analyzer.

3.3.1.1 Oxidation Catalyst Efficiency Check. Gas mixture standard with nominal concentration of 5 percent methane and 5 percent oxygen in nitrogen.

3.3.1.2 Reducation Catalyst Efficiency Check. Gas mixture standard with nominal concentration of 5 percent CO_2 in air.

3.3.1.3 Flame Ionization Detector Linearity Calibration Gases (3). Gas mixture standards with known methane (CH_4) concentrations in the 5–10 ppm, 500–1,000 ppm, and 5–10 percent range, in air. These gas standards are to be used to check the FID linearity as described in Section 4.4.1.1.

3.3.1.4 System Operation Standards (2). These calibration gases are required

*Mention of trade name does not constitute endorsement.

to check the total system operation as specified in Section 4.4.1.4. Two gas mixtures are required:

3.3.1.4.1 Gas mixture standard containing (nominal) 50 ppm CO, 50 ppm CH_4, 2 percent CO_2, and 15 ppm C_3H_8, prepared in air.

3.3.1.4.2 Gas mixture standard containing (nominal) 50 ppm CO, 50 ppm CH_4, 2 percent CO_2, and 1,000 ppm C_3H_8, prepared in air.

3.3.2 Condensate Recovery and Conditioning Apparatus. The calibration gas specified in paragraph 3.3.1.1 is required for performing an oxidation catalyst check according to the procedure of paragraph 4.4.2.

4. *Procedure.*

4.1 Sampling.

4.1.1 Sample Tank Evacuation. Either in the laboratory or in the field, evacuate the sample tank to 5 mm Hg absolute pressure or less (measured by a mercury U-tube manometer). Record the temperature, barometric pressure, and tank vacuum as measured by the manometer.

4.1.2 Sample Tank Leak Check. Leak check the gas sample tank immediately after the tank is evacuated. Once the tank is evacuated, allow the tank to sit for 30 minutes. The tank is acceptable if no change in tank vacuum (measured by the mercury manometer) is noted.

4.1.3 Assembly. Just prior to assembly, use a mercury U-tube manometer to measure the tank vacuum. Record this vacuum (P_{ti}), the ambient temperature (T_{ti}), and the barometric pressure (P_{bi}) at this time. Assuring that the flow control valve is in the closed position, assemble the sampling system as shown in Figure 1. Immerse the condensate trap body in dry ice to within 1 or 2 inches of the point where the inlet tube joins the trap body.

4.1.4 Leak Check Procedures.

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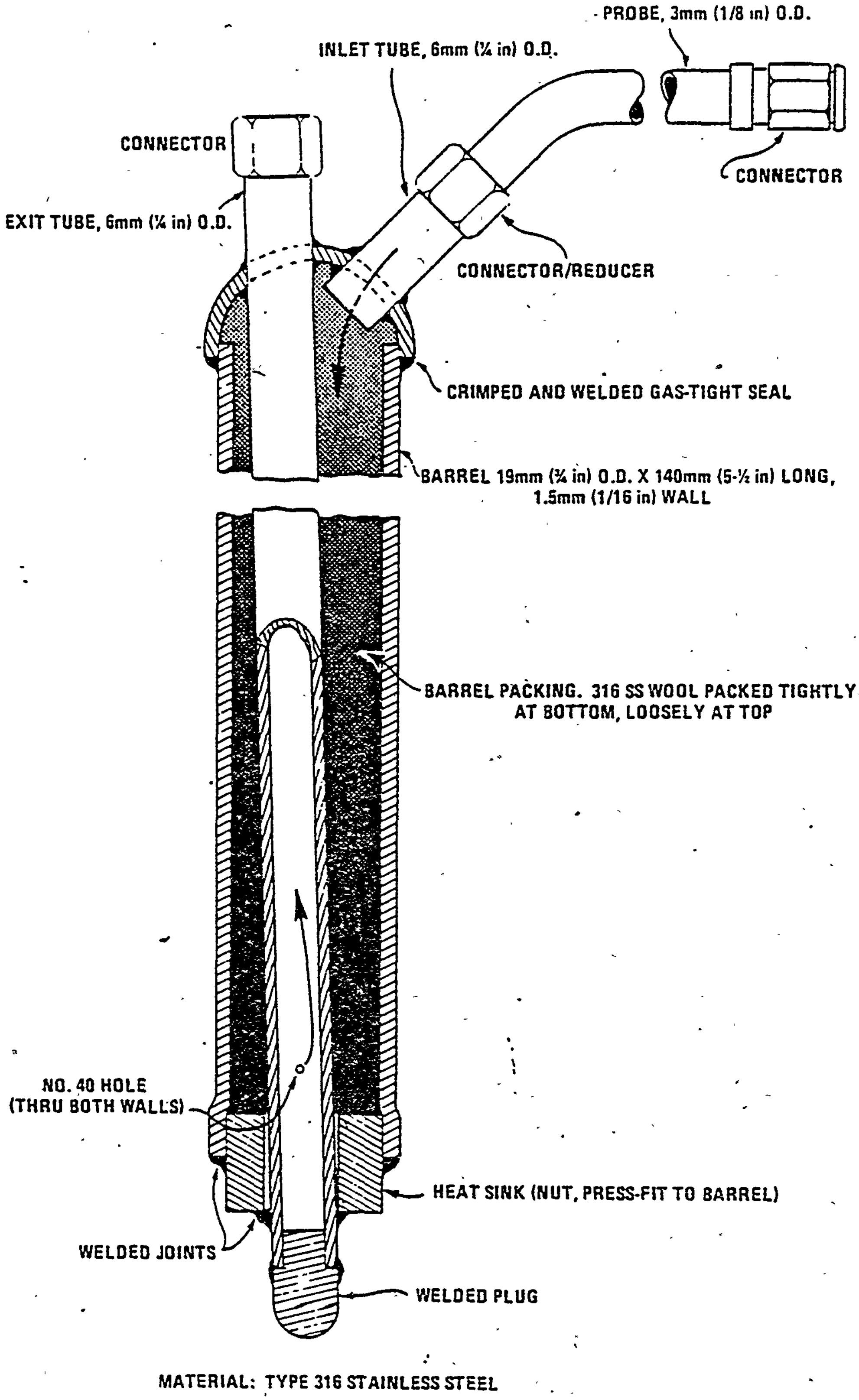

Figure 5. Condensate trap[2].

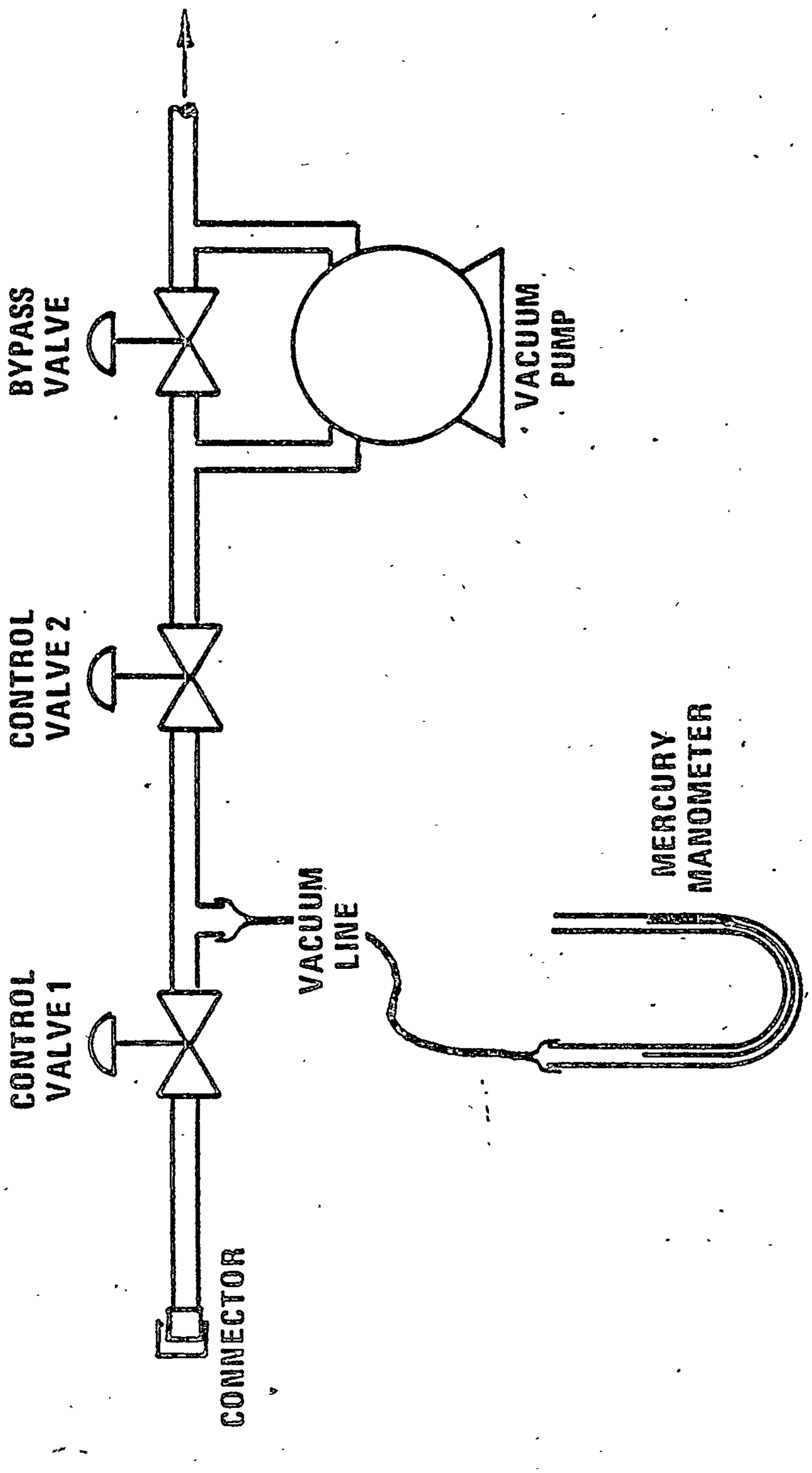

Figure 6. Leak check apparatus.

VOLATILE ORGANIC CARBON

FACILITY ____________________ SAMPLE LOCATION ____________________

LOCATION ____________________ OPERATOR ____________________

DATE ____________________ RUN NUMBER ____________________

TANK NUMBER ____________ TRAP NUMBER ____________ SAMPLE ID NUMBER ____________

TANK VACUUM, mm Hg		BAROMETRIC PRESSURE, mm Hg	AMBIENT TEMPERATURE, °C
PRETEST (MANOMETER) ________	(GAUGE) ________		
POST TEST (MANOMETER) ________	(GAUGE) ________		

LEAK RATE, mm Hg/5 min.:	TANK	TRAP HALF
PRETEST		
POST TEST		

TIME CLOCK/SAMPLE	GAUGE VACUUM, mm Hg	FLOWMETER SETTING	COMMENTS

Figure 7. Example Field Data Form.

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4.1.4.1 Pretest Leak Check. A pretest leak check is required. After the sampling train is assembled, record the tank vacuum as indicated by the vacuum gauge. Wait a minimum period of 15 minutes and recheck the indicated vacuum. If the vacuum has not changed, the portion of the sampling train behind the shut-off valve does not leak and is considered acceptable. To check the front portion of the sampling train, attach the leak check apparatus (Figure 6) to the probe tip. Evacuate the front half of the train (i.e., do not open the sampling train flow control valve) to a vacuum of at least 500 mm Hg. Close the shut-off valve on the leak check apparatus and record the vacuum indicated by the manometer on the data sheet (Figure 7). Allow the system to sit for 5 minutes and then recheck the vacuum. A change of less than 2 mm Hg for the 5-minute leak check period is acceptable. Record the front half leak rate (mm Hg/5-minute period) on the data form. When an acceptable leak rate has been obtained disconnect the leak check apparatus from the probe tip.

4.1.4.2 Post Test Leak Check. A leak check is mandatory at the conclusion of each test run. After sampling is completed, attach the U-tube manometer to the probe tip; minimize the amount of flexible line used. Open the sample train flow control valve for a period of 2 minutes or until the vacuum indicated on the manometer stabilizes, whichever occurs first; shut off the sample train flow control valve. Record the vacuums indicated on the manometer (front half) and on the tank vacuum gauge (back-half). After 5 minutes, recheck these vacuum readings. A leak rate of less than 2 mm Hg per 5-minute period is acceptable for the front half; the back half portion is acceptable if no visible change in the tank vacuum gauge occurs. Record the post test leak rate (mm Hg per 5 minutes), and then disconnect the manometer from the probe tip and seal the probe. If the sampling train does not pass the post test leak check, invalidate the run.

4.1.5 Sample Train Operation. Place the probe into the stack such that the probe is perpendicular to the direction of stack gas flow; locate the probe tip at a single preselected point. For stacks having a negative static pressure, assure that the sample port is sufficiently sealed to prevent air in-leakage around the probe. Check the dry ice level and add ice if necessary. Record the clock time and sample tank gauge vacuum. To begin sampling, open and adjust (if applicable) the flow control valve(s) of the flow control system utilized in the sampling train; maintain a constant flow rate (± 10 percent) throughout the duration of the sampling period. Record the gauge vacuum and flowmeter setting (if applicable) at 5-minute intervals. Select a total sample time greater than or equal to the minimum sampling time specified in the applicable subpart of the regulation; end the sampling when this time period is reached or when a constant flow rate can no longer be maintained. When the sampling is completed, close the gas sampling tank control valve. Record the final readings. Note: If the sampling had to be stopped before obtaining the minimum sampling time (specified in the applicable subpart) because a constant flow rate could not be maintained, proceed as follows: After removing the probe from the stack, remove the evacuated tank from the sampling train (without disconnecting other portions of the sampling train) and connect another evacuated tank to the sampling train. Prior to attaching the new tank to the sampling train, assure that the tank vacuum (measured on-site by the U-tube manometer) has been recorded on the data form and that the tank has been leak-checked (on-site). After the new tank is attached to the sample train, proceed with the sampling; after the required minimum sampling time has been exceeded, end the test.

4.2 Sample Recovery. After sampling is completed, remove the probe from the stack and seal the probe end. Conduct the post test leak check according to the procedures of paragraph 4.1.4.2. After the post test leak check has been conducted, disconnect the condensate trap at the flow metering system. Tightly seal the ends of the condensate trap; keep the trap packed in dry ice until analysis. Remove the flow metering system from the sample tank. Attach the U-tube manometer to the tank (keep length of flexible connecting line to a minimum) and record the final tank vacuum (P_t); record the tank temperature (T_t) and barometric pressure at this time. Disconnect the manometer from the tank. Assure that the test run number is properly identified on the condensate trap and evacuated tank(s).

4.3 Analysis.

4.3.1 Preparation.

4.3.1.1 TGNMO Analyzer. Set the carrier gas, air, and fuel flow rates and then begin heating the catalysts to their operating temperatures. Conduct the calibration linearity check required in paragraph 4.4.1.1 and the system operation check required in paragraph 4.4.1.4. Optional: Conduct the catalyst performance checks required in paragraphs 4.4.1.2 and 4.4.1.3 prior to analyzing the test samples.

4.3.1.2 Condensate Recovery and Conditioning Apparatus. Set the carrier gas flow rate and begin heating the catalyst to its operating temperature. Conduct the catalyst performance check required in paragraph 4.4.2 prior to oxidizing any samples.

4.3.2 Condensate Trap Carbon Dioxide Purge and Evacuated Sample Tank Pressurization. The first step in analysis is to purge the condensate trap of any CO_2 which it may contain and to simultaneously pressurize the gas sample tank. This is accomplished as follows: Obtain both the sample tank and condensate trap from the test run to be analyzed. Set up the condensate recovery and conditioning apparatus so that the carrier flow bypasses the condensate trap hook-up terminals, bypasses the oxidation catalyst, and is vented to the atmosphere. Next, attach the condensate trap to the apparatus and pack the trap in dry ice. Assure that the valve isolating the collection vessel connection from the atmospheric vent is closed and then attach the gas sample tank to the system as if it were the intermediate collection vessel. Record the tank vacuum on the laboratory data form. Assure that the NDIR analyzer indicates a zero output level and then switch the carrier flow through the condensate trap; immediately switch the carrier flow from vent to collect and open the valve to the tank. The condensate trap recovery and conditioning apparatus should now be set up as indicated in Figure 8. Monitor the NDIR; when CO_2 is no longer being passed through the system, switch the carrier flow so that it once again bypasses the condensate trap. Continue in this manner until the gas sample tank is pressurized to a nominal gauge pressure of 800 mm mercury. At this time, isolate the tank, vent the carrier flow, and record the sample tank pressure (P_{tf}), barometric pressure (P_{bf}), and ambient temperature (T_{tf}). Remove the gas sample tank from the system.

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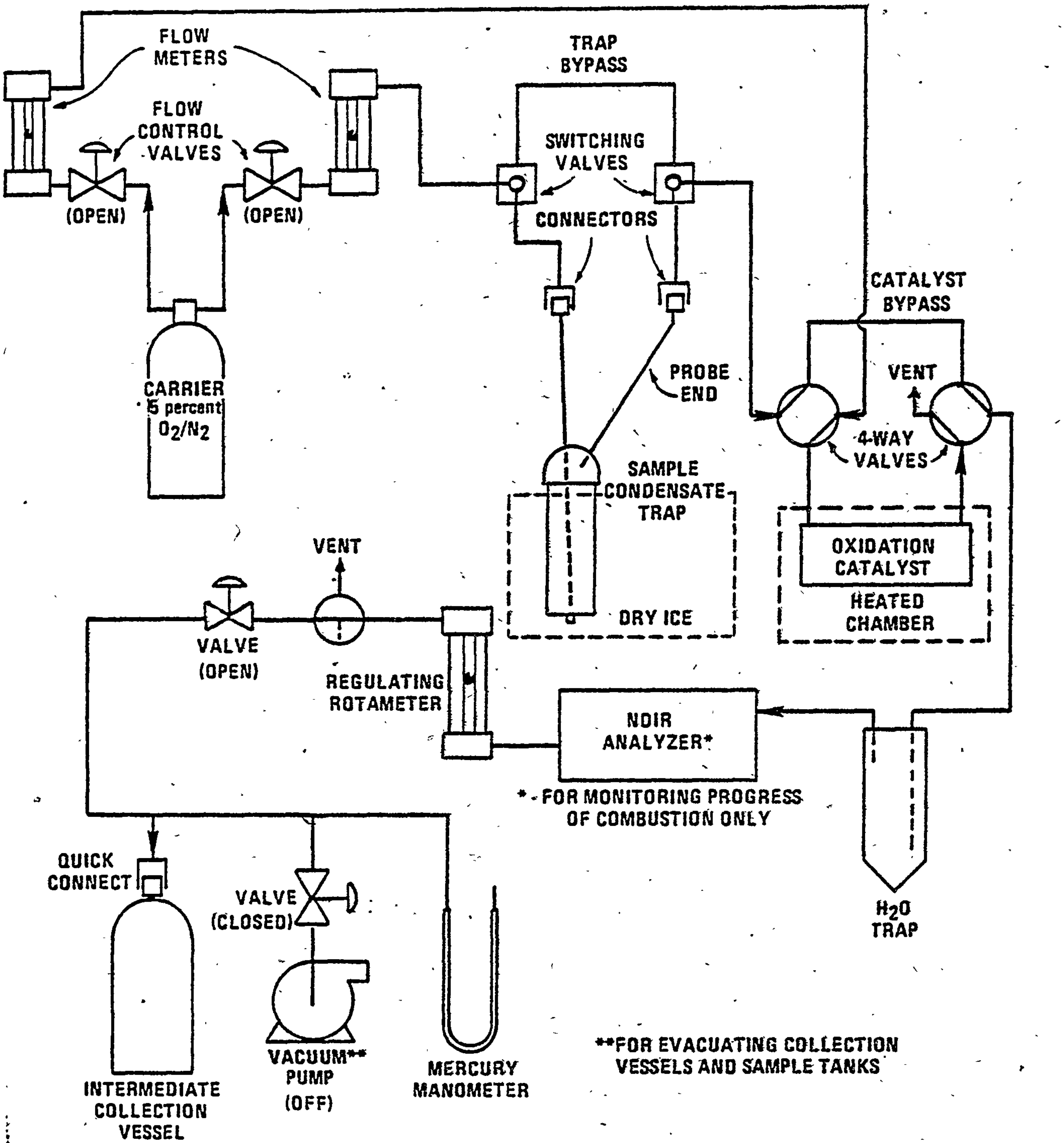

Figure 8. Condensate recovery and conditioning apparatus, carbon dioxide purge.

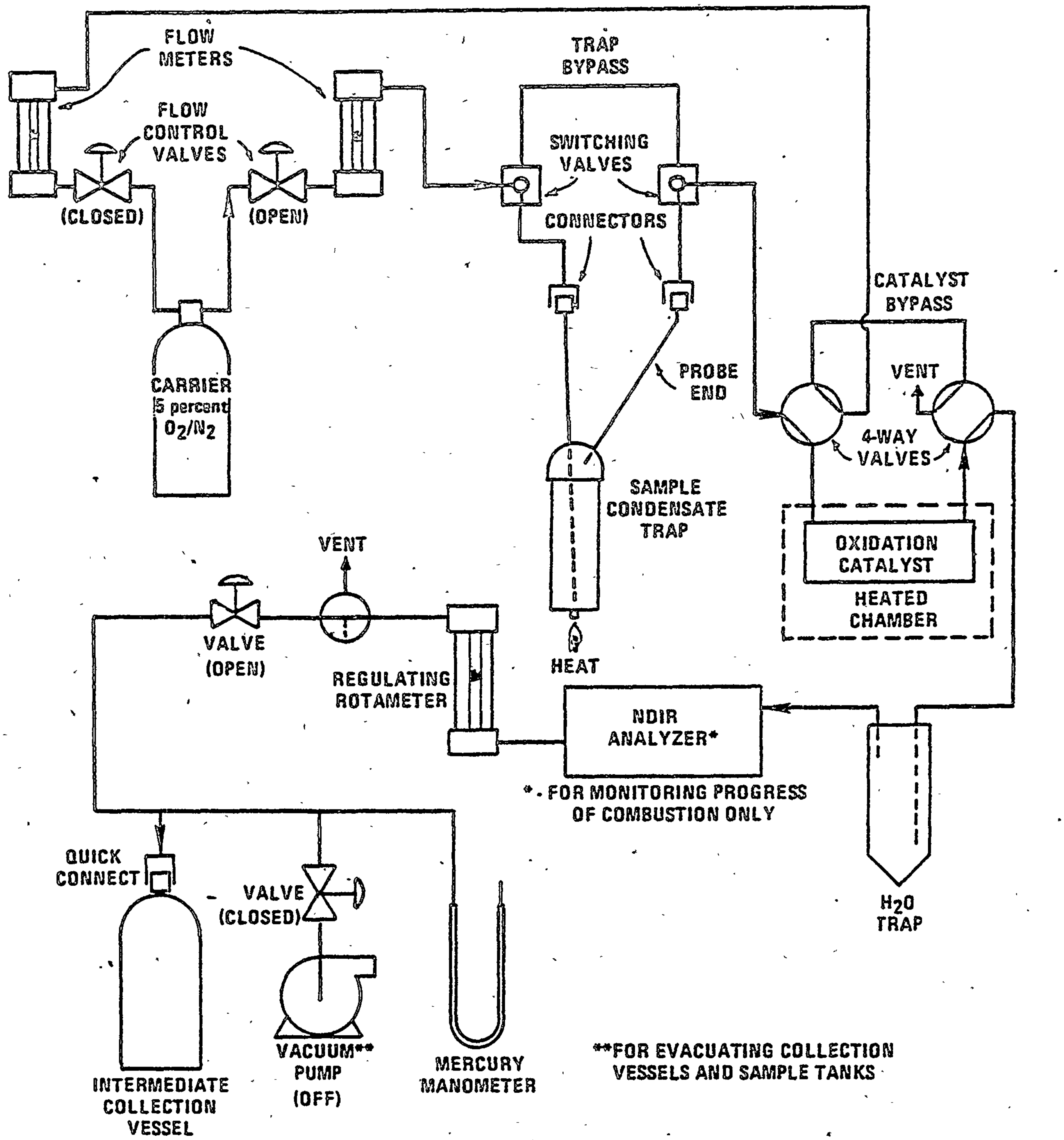

Figure 9. Condensate recovery and conditioning apparatus, collection of trap organics.

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4.3.3 Recovery of Condensate Trap Sample. Oxidation and collection of the sample in the condensate trap is now ready to begin. From the step just completed in paragraph 4.3.2 above, the system should be set up so that the carrier flow bypasses the condensate trap, bypasses the oxidation catalyst, and is vented to the atmosphere. Attach an evacuated intermediate collection vessel to the system and then, switch the carrier so that it flows through the oxidation catalyst. Monitor the NDIR and assure that the analyzer indicates a zero output level. Switch the carrier from vent to collect and open the collection tank valve; remove the dry ice from the trap and then switch the carrier flow through the trap. The system should now be set up to operate as indicated in Figure 9.

Begin heating the condensate trap. The trap should be heated to a temperature at which the trap glows a "dull red" (approximately 600° C) and should be maintained at this temperature for at least 5 minutes. During oxidation of the condensate trap sample, monitor the NDIR to determine when all the sample has been removed and oxidized (indicated by return to baseline of NDIR analyzer output). When complete recovery has been indicated, remove the heat from the trap. However, continue the carrier flow until the intermediate collection vessel is pressurized to a gauge pressure of 800 mm Hg (nominal). When the vessel is pressurized, vent the carrier; measure and record the final intermediate collection vessel pressure (P_f) as well as the barometric pressure (P_{bv}), ambient temperature (T_v), and collection vessel volume (V_v).

4.3.4 Analysis of Recovered Condensate Sample. After the preparation steps in paragraph 4.3.1 have been completed, the analyzer is ready for conducting analyses. Assure that the analyzer system is set so that the carrier gas is routed through the reduction catalyst to the FID (flow through the separation column and oxidation catalyst is optional). Attach the intermediate collection vessel to the tank inlet fitting of the TGNMO analyzer. Purge the sample loop with sample and then inject a preliminary sample in order to determine the appropriate FID attenuation. Inject triplicate samples from the intermediate collection vessel and record the values (C_{cm}). When appropriate, check the instrument calibration according to the procedures of paragraph 4.4.1.4.

4.3.5 Analysis of Gas Sample Tank. Assure that the analyzer is set up so that the carrier flow is routed through the separation column as well as both the oxidation and reduction catalysts. During analysis for the nonmethane organics the separation column is operated as follows: First, operate the column at −78° C (dry ice temperature) to elute the CO and CH_4. After the CH_4 peak, operate the column at 0° C to elute the CO_2. When the CO_2 is completely eluted, switch the carrier flow to backflush the column and simultaneously raise the column temperature to 100° C in order to elute all nonmethane organics. (Exact timings for column operation are determined from the calibration standard). Attach the gas sample tank to the tank inlet fitting of the TGNMO analyzer. Purge the sample loop with sample and inject a preliminary sample in order to determine the appropriate FID attenuation for monitoring the backflushed non-methane organics. Inject triplicate samples from the gas sample tank and record the values obtained for the nonmethane organics (C_{tm}). When appropriate, check the instrument calibration according to the procedures of paragraph 4.4.1.4.

4.4 Calibration. Maintain a record of performance of each item.

4.4.1 TGNMO Analyzer.

4.4.1.1 FID Calibration and linearity check. Set up the TGNMO system so that the carrier gas bypasses the oxidation and reduction catalysts. Zero and span the FID by injecting samples of the high value (5–10 percent) calibration gas (paragraph 3.3.1.3) and adjusting the instrument output to the correct level. Then check the instrument linearity by injecting triplicate samples of the low (5–10 ppm) and mid-range (500–1,000 ppm) calibration gases (paragraph 3.3.1.3). The system linearity is acceptable if the results (average for triplicate samples of each gas) are within ±5 percent of the expected values. This calibration and linearity check shall be conducted prior to analyzing each set of samples (i.e., samples from a given source test).

4.4.1.2 Oxidation Catalyst Efficiency Check. This check should be performed on a frequency established by the amount of use of the analyzer and the nature of the organic emissions to which the catalyst is exposed. As a minimum, perform this check prior to putting the analyzer into service.

To confirm that the oxidation catalyst is functioning in a correct manner, the operator must turn off or bypass the reduction catalyst while operating the analyzer in an otherwise normal fashion. Inject triplicate samples of the methane standard gas (paragraph 3.3.1.1) into the system. If oxidation is adequate, the only gas that will then reach the detector will be CO_2, to which the FID has no response. If a response is noted, the oxidation catalyst must be replaced.

4.4.1.3 Reduction Catalyst Efficiency Check. This check should be performed on a frequency established by the amount of use of the analyzer. As a minimum, perform this check prior to putting the analyzer into service. To confirm proper operation of the reduction catalyst, the operator must bypass the oxidation catalyst while operating the analyzer in an otherwise normal manner. After setting the carrier flow to bypass the oxidation catalyst, inject triplicate samples of the carbon dioxide standard gas (Section 3.3.1.2). The catalyst operation is acceptable if the average response of the triplicate CO_2 sample injections is within ±2 percent of the expected value and no one CO_2 sample injection varies by more than ±5 percent from the expected value.

4.4.1.4 System Operation Check. This system check should be conducted at a frequency consistent with the amount of use and the reliability of the particular analyzer. As a minimum, this system check shall be conducted before and after each set of emission samples is analyzed. If this system check is not successfully completed at the conclusion of the analyses, the results shall be invalidated. Operate the TGNMO analyzer in a normal fashion, passing the carrier flow through the separation column and both the oxidation and reduction catalysts. Inject triplicate samples of the two mixed gas standards specified in Section 3.3.1.4. The system operation is acceptable if, for each gas mixture, the average non-methane organic value for the triplicate samples is within ±3 percent of the expected value and no one sample analysis varies by more than ±5 percent from the average value for the triplicate samples.

4.4.2 Condensate Trap Recovery and Conditioning Apparatus Oxidation Catalyst Check. This catalyst check should be conducted at a frequency consistent with the amount of use of the catalyst, as well as, the nature and concentration level of the organics being recovered by the system. As a minimum, perform this check prior to and immediately after conditioning each set of emission sample traps.

Set up the condensate trap recovery system so that the carrier flow bypasses the trap inlet and is vented to the atmosphere at the system outlet. Assure that the tank collection valve is closed and then attach an evacuated intermediate collection vessel to the system. Connect the methane standard gas cylinder (Section 3.3.1.1) to the system's condensate trap connector (probe end, figure 4). Adjust the system valving so that the standard gas cylinder acts as the carrier gas; switch off the carrier and use the cylinder of standard gas to supply a gas flow rate equal to the carrier flow normally used during trap sample recovery. Now switch from vent to collect in order to begin collecting a sample. Continue collecting a sample in the normal manner until the intermediate vessel is filled to a nominal pressure of 300 mm Hg. Remove the intermediate vessel from the system and vent the carrier flow to the atmosphere. Switch the valving to return the system to its normal carrier gas and normal operating conditions. Set up the TGNMO analyzer to operate with the oxidation and reduction catalysts bypassed. Inject a sample from the intermediate collection vessel into the analyzer. The operation of the condensate trap recovery system oxidation catalyst is acceptable if oxidation of the standard methane gas was 99.5 percent complete, as indicated by the response of the TGNMO analyzer FID.

4.4.3 Gas Sampling Tank. The volume of the gas sampling tanks used must be determined. Prior to putting each tank in service, determine the tank volume by weighting the tanks empty and then filled with water; weight to the nearest 0.5 gm and record the results.

4.4.4 Intermediate Collection Vessel. The volume of the intermediate collection vessels used to collect CO_2 during the analysis of the condensate traps must be determined. Prior to putting each vessel into service, determine the volume by weighting the vessel empty and then filled with water; weigh to the nearest 0.5 gm and record the results.

5. *Calculations.*

Note. All equations are written using absolute pressure; absolute pressures are determined by adding the measured barometric pressure to the measured gauge pressure.

5.1 Sample Volume. For each test run, calculate the gas volume sampled:

$$V_s = 0.386\ V\left(\frac{P_t}{T_t}\right)-\left(\frac{P_{t_i}}{T_i}\right)$$

5.2 Noncondensible Organics. For each collection tank, determine the concentration of nonmethane organics (ppm C):

$$C_t = \frac{\frac{P_{tf}}{T_{tf}}}{\frac{P_t}{T_t}-\frac{P_{ti}}{T_{ti}}} \times \frac{1}{r} \times \sum_{j=1}^{r} C_{tm_j}$$

5.3 Condensible Organics. For each condensate trap determine the concentration of organics (ppm C):

$$C_c = 0.386\ \frac{V_v \times P_f}{V_s \times T_f} \times \frac{1}{N} \times \sum_{k=1}^{n} C_{cm_k}$$

5.4 Total Gaseous Nonmethane Organics (TGNMO). To determine the TGNMO concentration for each test run, use the following equation:

$C=C_t+C_c$

Where:

C=Total gaseous nonmethane organic (TGNMO) concentration of the effluent, ppm carbon equivalent.

C_c=Calculated condensible organic (condensate trap) concentration of the effluent, ppm carbon equivalent.

C_{cm}=Measured concentration (TGNMO analyzer) for the condensate trap (intermediate collection vessel), ppm methane.

C_t=Calculated noncondensible organic concentration of the effluent, ppm carbon equivalent.

C_{tm}=Measured concentration (TGNMO analyzer) for gas collection tank sample, ppm methane.

P_f=Final pressure of intermediate collection vessel, mm Hg., absolute.

P_{ti}=Gas sample tank pressure prior to sampling, mm Hg, absolute.

P_t=Gas sample tank pressure after sampling, but prior to pressurizing, mm Hg, absolute.

P_{tf}=Final gas sample tank pressure after pressurizing, mm Hg, absolute.

T_f=Final temperature of intermediate collection vessel, °K.

T_{ti}=Gas sample tank temperature prior to sampling, °K.

T_t=Gas sample tank temperature at completion of sampling, °K.

T_{tf}=Gas sample tank temperature after pressurizing, °K.

V=Gas collection tank volume, dscm.

V_v=Intermediate collection tank volume, dscm.

V_s=Gas volume sampled, dscm.

r=Total number of analyzer injections of tank sample during analysis (where j=injection number, 1 . . . r).

n=Total number of analyzer injections of condensible intermediate collection vessel during analysis (where k=injection number, 1 . . . n).

Standard Conditions=Dry, 760 mm Hg, 293°K.

6. *Bibliography.*

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federal register

Friday
October 5, 1979

Part VI

Department of Energy

Bonneville Power Administration

Allocation of Firm Electric Energy and System Reserve Energy From the Federal Columbia River Power System; Proposed Policy and Formula and Opportunity To Comment

DEPARTMENT OF ENERGY

Bonneville Power Administration

Proposed Policy and Formula To Guide Allocation of Firm Electric Energy and System Reserve Energy From the Federal Columbia River Power System and Opportunities for Public Review and Written Comment

AGENCY: Bonneville Power Administration (BPA or Bonneville), Department of Energy.

ACTION: Notice of Proposed Policy and formula to Guide Allocation of Firm Electric Energy and System Reserve Energy from the Federal Columbia River Power System (FCRPS) and Opportunities for Public Review and Written Comment.

SUMMARY: In 1976 BPA notified its preference customers that it would lack sufficient resources to fully meet their firm energy requirements after June 30, 1983. Since then, BPA has developed a proposed policy and formula to guide the allocation of firm energy and system reserve energy beginning July 1, 1983. This proposal reflects a public involvement effort underway since January 1978.

BPA is now publishing the proposal for widespread review and comment. This proposal provides initially for base allocations to existing preference customers from FCRPS hydro and net-billed thermal resources. As existing contracts with direct-service industrial and Federal agency customers expire between 1981 and 1993, the firm energy which becomes available will be reallocated to new and existing preference customers. As of July 1, 1991, any distinction between existing and new preference customers will be eliminated. Starting July 1, 1983, 15 percent of the available BPA firm energy will be reserved for awards to preference customers which implement approved conservation programs and achieve either at least 15 percent savings in their individual forecasted firm energy requirements in the 1989–1990 operating year or sooner, or all energy savings within their individual capabilities. It will be incumbent upon each preference customer to develop and implement a program that is tailored to its individual system characteristics.

BPA representatives will explain the proposed policy and answer questions at eight Public Information Forums—one in Portland, Oregon, October 31, and the others throughout the Pacific Northwest during the first week of November 1979. Public comment forums will be scheduled in 1980. Supporting documents will be available for review and copying at BPA headquarters 2 weeks after the date of publication of this Notice. Written comments are welcome at any time after publication and until 15 days after the last Public Comment Forum.

BACKGROUND: BPA and the Pacific Northwest face an energy insufficiency in the 1980's. While the region's utilities have reduced their forecasted future energy needs in all years through 1990, the May 1979 *Power Outlook* shows greater potential energy deficits in the mid-to-late 1980's than the 1978 *Power Outlook* indicated would probably be the case. The projected deficits are greater, despite the fact that the projected needs have been reduced. This is the result of further delays in the scheduled completion of thermal plants upon which the region is relying to meet its load growth needs.

BPA is the Federal power marketing agency which sells the power produced by 30 Federal hydroelectric projects constructed and operated by the U.S. Army Corps of Engineers and the U.S. Bureau of Reclamation in the Pacific Northwest (defined by law to include Oregon, Washington, Idaho, Montana west of the Continental Divide, and portions of Wyoming, Utah, Nevada, and California). As a result of cooperative efforts to provide for supplementary thermal resource development, constructed by non-Federal interests, BPA also acquires and sells some thermal power. BPA supplies more than 50 percent of the total energy requirements in the Pacific Northwest.

BPA serves 160 customers in the Pacific Northwest and the Pacific Southwest. However, the Pacific Northwest Regional Preference Act of 1964 accords geographic preference and priority for the electric energy generated at Federal hydroelectric projects in the region to Pacific Northwest customers. Under the provisions of the Bonneville Project Act of 1937, as amended, public bodies and cooperatives (BPA's preference customers or PC's) in the Pacific Northwest are entitled to statutory preference and priority for the BPA firm energy available for sale. Currently, BPA has power sales contracts with 116 preference customers.

BPA also has power sales contracts to sell firm energy to 6 Federal agencies and 17 direct-service industrial (DSI or DSI's) customers located in the region. Under the geographic preference clause of the Hungry Horse Dam Act of 1944, firm energy is also sold to the Montana Power Company, an investor-owned utility (IOU) or IOU's), for use within the State of Montana.

In the past, BPA generally had sufficient power available to satisfy the requirements of all customers, including those to whom preference and priority are not accorded by law. For some years, BPA has known that it could not continue to contract to meet the firm energy requirements of its customers without acquiring additional resources. The necessary resources have not materialized. Therefore, BPA has notified its existing preference customers (PC or PC's) that it will not have sufficient firm energy available after June 30, 1983, to continue to meet their load growth and satisfy BPA's other firm energy commitments. In August 1973, firm power sales contracts with investor-owned utilities (IOU or IOU's) expired. BPA's power supply was not adequate to enable it to offer new power sales contracts for firm energy to the IOU's. In addition, BPA has stated that it will be unable to offer new power sales contracts on the same terms and conditions to its existing direct-service industrial (DSI or DSI's) customers when their present contracts expire. Representatives of the DSI's have indicated that they will apply for service from their local utilities.

BPA will serve its existing Federal agency customers until their contracts expire. Under the provisions of the Bonneville Project Act Federal agencies are not entitled to statutory preference and priority for the BPA firm energy available for sale. They will have to apply for service from their local utilities after their contracts expire or make other arrangements. BPA anticipates that existing PC's and preference applicants (PA's) will apply for the firm energy which will become available for allocation after existing BPA contracts with DSI's and Federal agencies expire.

BPA recognizes that its marketing policies affect the well-being of the region's economy and the resource planning of existing and prospective customers. Therefore, BPA believes a final allocation policy and formula, a final environmental impact statement, and the BPA conservation program specifics should be completed prior to the date existing power sale contracts begin to expire—1981 in the case of nonpreference customers and 1983 in the case of preference customers.

Otherwise, prolonged uncertainty over the substance and mechanics of a long-term allocation policy affects the capability of BPA's customers to provide for energy supplies which the BPA allocations cannot satisfy. If PC's are overly optimistic about what their share of BPA firm energy is likely to be, shortages could occur whose impacts would vary in intensity from place to place. If preference utilities are unduly pessimistic, they may construct excess generating capacity. IOU's are also affected by the uncertainty about what future requirements will be imposed on them, depending on whether or not new public bodies and cooperatives are formed which receive BPA allocations of firm energy, and whether or not the IOU's receive applications for service from DSI's and Federal agencies which cannot be readily served by BPA preference customers.

Since the DSI's and the Federal agencies must secure alternative power supplies after their current contracts with BPA expire, BPA expects that the costs of their energy supplies will rise. The policy does not cushion the economic impact on the DSI's and Federal agencies which will occur when BPA service ends. Approximately 85 percent of the composite BPA industrial customer load (ten DSI's at 14 sites) in calendar year (CY) 1978, can readily be served by BPA's existing PC's. Seven DSI's with plants at seven sites account for the remaining 15 percent of the composite industrial customer load in CY 1978. Presumably, these industries will apply for service from the nearest IOU's or make other arrangements.

BPA *is proposing that all firm loads* served by a PC be included in its net firm energy requirements eligible for an allocation of BPA firm energy, with one exception: new or expanding single loads which equal or exceed 10 average megawatts in a 3-year period commencing from the date of initial service and which have not been contracted for or committed to prior to September 1, 1979. Those amounts of any loads which BPA or any Pacific Northwest utilities contracted to serve as nonfirm loads prior to September 1, 1979, will be regarded as new or expanding single loads if they become firm loads. Some examples of present nonfirm loads are the interruptible (first) and reserve (second) quartiles of the current DSI loads.

Under its existing contracts, BPA markets interruptible energy for meeting loads specifically suited for this lower quality supply. Approximately 25 percent of the DSI load is suitable for this supply. This energy, which is generally regarded as energy above critical streamflows, is available when FCRPS capability exceeds what is needed to meet contracted firm energy requirements. BPA markets this energy under contracts which contain provisions that permit BPA to interrupt deliveries for any purpose. This facilitates efficient operation of the FCRPS, provides an assured market for nonfirm energy, and supplies a load without requiring additional firm generating resources. BPA proposes to contine marketing interruptible energy to PC's which have loads suitable for such energy. Since BPA will no longer provide direct service to the DSI's after contracts expire, local utilities may purchase interruptible energy to serve these types of loads.

Under its existing contracts, BPA markets a block of energy to the DSI's which provides the FCRPS with both capacity and energy reserves. Approximately 25 percent of the DSI load is served from this supply. BPA makes use of these system reserves by restricting deliveries to the DSI's when necessary to protect BPA's firm energy commitments to its PC's or to back up a PC's own generation. BPA proposes to continue marketing system reserve energy after the current DSI contracts expire. However, the system reserve energy will be made available to PC's with BPA retaining rights to restrict deliveries for its own and contract purposes.

Six Federal agencies with eight points of delivery, accounting for 68 percent of the composite BPA Federal agency customer load in calendar year 1978, can readily be served by BPA preference customers. BPA is proposing that these loads, which are considered firm, be included in these preference customers' net firm energy requirements eligible for an allocation of BPA firm energy. The remaining two agencies with three points of delivery, that account for 32 percent of the composite BPA Federal agency customer load in calendar year 1978, will have to apply for service from the nearest IOU's or make other arrangements.

BPA has contracted to meet the net firm energy requirements of existing PC's who are computed demand customers, and the requirements, including contract demands, of all other existing PC's subject to limitations on obligations to serve large new loads and the right to restrict power delivery obligations on proper notice. In accordance with provisions in these contracts, BPA issued a Notice of Insufficiency on June 24, 1976. The Notice states that BPA cannot meet PC firm energy load growth after July 1, 1983, except for those utilities whose loads are less than the guaranteed minimum allocation. Allocation formulas incorporated in the existing contracts determine allocations of firm energy for the duration of each contract.

Prior to the Notice of Insufficiency, BPA had advised new PA's that firm energy would not be available for sale until additional resources became available and/or existing contracts expired. Nonetheless, newly formed public bodies and cooperatives have applied for service. BPA anticipates that other public bodies and cooperatives may yet be formed which will also request allocations of firm energy.

Pursuant to 16 U.S.C. 832–832l, 16 U.S.C. 837–837h, 16 U.S.C. 838–838k, 16 U.S.C. 825a, 43 U.S.C. 593a, and other applicable statutes, the BPA Administrator has developed a proposed allocation policy and formula to guide the reallocation of the firm energy and system reserve energy which will become available as all outstanding power sales contracts expire between May 11, 1981, and September 20, 1994, and to guide the allocation of resources available to the FCRPS each operating year in circumstances where they may be augmented or reduced. The policy also provides for revised allocations among PC's and service to new as well as existing PC's. The policy proposal is included in Part I of this notice.

In brief, BPA is proposing that public bodies and cooperatives it does not presently serve will be required to submit applications 30 months or more before firm energy is scheduled to become available due to contract expirations and resource additions. From July 1, 1983, through June 30, 1991, new preference customers which satisfy the criteria for service specified under (1) *Class(es) of Customer(s) to be Served* in the proposed policy will be eligible, as a group, for allocations totalling up to ⅔ of the firm energy available for allocation or reallocation during the operating year in which they first receive service. Starting with the second year of service, they will receive allocations on the same basis as existing BPA customers.

From July 1, 1983, through June 30, 1991, existing PC's will receive allocations in accordance with the provisions in their current contracts, if they adopt a satisfactory conservation program and implementation plan. By extending the contract provisions, service continues to more than 60 percent of BPA's existing PC's which might otherwise be without a BPA firm energy allocation. These customers will realize considerable savings in energy costs, since they will not have to purchase higher cost energy elsewhere.

The economic impact on all PC's depends on a number of variables such as (1) the actual amount(s) of additional firm energy available from BPA each operating year, (2) the number and size of new preference customers served by BPA, (3) the effectiveness of the customers' conservation programs, taken individually and in the aggregate, (4) the timing of applications by preference applicants, and (5) the actual resource cost(s) of resource additions, which may or may not be reflected in forecasts.

After July 1, 1991, BPA will allocate energy on the basis of the relationship of each customer's total net firm energy requirements to all customers' total net firm energy requirements multiplied by the total amount of power BPA has available for allocation, less the 15 percent for the conservation reserve. Individual customer allocations will be increased for achievements in energy conservation, as provided under (4) *Conservation* in the proposed policy.

Prior to July 1, 1991, all BPA allocations will not be calculated on a pro rata basis and, therefore, they will not reflect a full sharing of the economic benefits and costs of BPA firm energy among BPA customers. The policy includes a feature, (8) *Sharing of Benefits and Costs,* to assure that the distribution of benefits and costs will more closely approximate what would otherwise be the case after July 1, 1991, when all PC's will receive pro rata allocations. This feature may cushion the economic change which would otherwise occur at that time by providing for a transition adjustment to the extent the new contracts permit.

BPA is proposing that allocations of firm energy be made under the provisions of new contracts to be offered to existing PC's and to PA's eligible for an allocation. The new contracts will become effective when executed and terminate July 1, 2001. These contracts will contain allocation provisions which will be effective July 1, 1983, or later in certain circumstances, for the period(s) specified in the contract provisions. BPA recognizes that an existing preference customer may elect to continue with its existing contract until expiration, or not to sign the new contract offered. The policy has addressed this possibility.

The allocation policy development process reflects prior consultation with BPA customers, state and local governments, the PNW Congressional delegation, other Federal agencies, public interest groups, and consumers. BPA initiated the public involvement process by publishing a "Notice of Intent to Develop Formula for Allocation of Electric Energy" in the Federal Register. (43 FR 3611) and announcing that it would follow the BPA "Procedure for Public Participation in Marketing Policy Formulation" (42 FR 62950, December 14, 1977) to offer its customers and the public the opportunity to participate in formulating the policy and formula.

The Notice of Intent linked the 1976 Notice of Insufficiency, the post-July 1, 1983 allocations by the existing contract formula, and the need for a long-term policy and formula to guide the allocations of firm energy which will become available as a result of contract expirations, the allocations of firm energy which becomes available to the FCRPS as new resources are acquired, irrespective of source, or the revised allocations occasioned by reductions in firm energy available for marketing. The Notice of Intent also indicated that it is probable that new public bodies and cooperative will be formed which would be eligible for an allocation of BPA firm energy, and that their applications would have to be considered when BPA allocates firm energy.

BPA publicized the allocations policy development process through public mailings, news releases, and advertisements. The process to date has included briefings, discussion meetings, and analyses of views and suggestions received from the public on the development of policy alternatives, allocation policy procedure, and supporting analyses. The staff summary of the public comments will be made avialable to anyone who request a copy.

The allocation policy issues identified and discussed most frequently by the public include:

(1) the class(es) of BPA customer(s) to be served (current preference customers, new preference customers, Federal agencies, DSI's Pacific Northwest IOU's, Pacific Southwest customers served by the Intertie, and British Columbia Hydro);

(2) the extent to which BPA should require customers to commit their own non-Federal assured resources to meet their own load requirements before BPA determines their allocations;

(3) the types of loads to be served (i.e., the end uses of the firm energy BPA wholesales to its utility customers who, in turn, sell it, at retail, to consumers);

(4) the methods employed to determine load requirements and the amount of energy expected to be available to meet those loads;

(5) the extent and availability of sytem energy reserves;

(6) the durations and terms of the allocations;

(7) minimum allocations to preference customers;

(8) grades of power;

(9) rates charged for firm power; and

(10) conservation.

BPA conducted a policy analysis which addressed the issues identified in the Notice of Intent and considered all the public comments.

BPA received over 140 letters in response to the Notice of Intent and subsequent requests for public comments and suggestions. The majority of the respondents (about 70 percent) were from the general public. The remainder were utility and utility organizations, governors and state agencies, counties and municipalities, granges and other interested groups, the United States Navy, a state legislator, the Bureau of Mines, and a direct-service industry organization.

Approximately one-third of the comments related to "class of BPA customers." The most common remark was to give priority to preference customers. The next largest group favored equal sharing of resources among public agencies and investor-owned utilities. A substantial minority thought that BPA should serve all users equally without preference.

The next two largest categories of comment pertain to "rates" and "types of consumer sector loads served." With respect to rates, the most often mentioned rate factor was cost of production. There were extensive comments proposing a wide variety of rate designs including lifeline rates, interruptible services, peak load pricing, inverted rates, and others. There was no consensus on a preferred scheme. With respect to types of consumer sector loads served, the most frequent comment was to give first priority to domestic and rural consumers. The next largest group noted that the needs of people should be met before the needs of industry. A substantial minority would ignore the types of loads served and distribute power equally to all users.

The remaining comments largely addressed six other allocation issues: load determination, customer resources committed to load, grades of power, notice and duration, minimum allocations, conservation, amounts of power to be allocated. A wide variety of approaches to each issue was suggested.

In recent months, the analysis has concentrated on six major alternatives which incorporate varying approaches to the issues. BPA tested their technical feasibility and potential ramifications. As a result, the alternatives and associated methods of allocation have undergone modification. The proposed policy and other alternatives in their current configurations are displayed in the table entitled *Comparison of Proposed and Alternative Allocation Policies* included in Part IV of this Notice.

BPA considered the following evaluation criteria in assessing the alternatives: technical adequacy, reasonableness, potential economic and environmental impacts, equity, conformity with existing statutes, conservation, policy continuity, and ease of administration and public understanding. As a result, BPA proposes to implement Allocation Policy Alternative 3, subject to public comment, and additional economic and environmental analyses contemplated under applicable statutes and rules and regulations.

BPA believes that this proposal serves the public interest, since it (1) provides a method to efficiently utilize and promote widespread use in the Pacific Northwest of existing and prospective Federal firm energy resources, and (2) relies on conservation to supplement the limited Federal resource. Conservation represents the primary means available to the region in the 1980's to cope with energy deficits. The proposed policy could be implemented under existing statutory authorities, and it is conducive to achievement of many regional and national energy-related goals incorporated in State and Federal laws.

The BPA allocation proposal minimizes the degree of deviation from current BPA policies upon which BPA customers have long relied and on the basis of which they have made substantial financial and other commitments. The primary changes are to (1) make the Federal energy available to existing preference customers and new preference applicants; (2) establish a conservation reserve totalling 15 percent of the total firm energy available for allocation to preference customers; (3) require each preference customer to institute a conservation program/implementation plan as a condition for eligibility for additional allocations of firm energy from the conservation reserve; (4) terminate the fixed base allocation and the 25 MW minimum allocation to existing preference customers on July 1, 1991; (5) end direct firm energy sales to current Federal agency and DSI customers after their existing power sales contracts expire, (6) establish an offset energy arrangement to assure that the sharing of benefits and costs among BPA customers will more closely approximate what will occur after July 1, 1991, when all customers will receive pro rata allocations based on their net firm energy requirements; (7) market system reserve energy to PC's as a separate class of power; and (8) market interruptible energy to PC's to serve loads suitable for this lower quality of supply.

BPA will hold eight Public Information Forums on this proposed policy. One, a more technical session, will be held in Portland, Oregon, October 31, 1979. The other seven will be held throughout the Pacific Northwest during the first week of November 1979 to explain the proposal, present the general findings of its supporting analyses, and answer questions on the proposal and alternatives. BPA will also hold Public Comment Forums to receive oral comments at a future date or dates in 1980 to be announced later in a separate Notice and by mail and newspaper advertisement. Interested parties are urged to send their written comments on the proposal to BPA as soon as possible after this Notice is published. Written comments should be submitted to the Public Involvement Coordinator, Bonneville Power Administration, P.O. Box 12999, Portland, Oregon 97212.

The expiration date of the public comment period will be firmly established at the time the Public Comment Forums are scheduled and the dates announced. BPA accepts written comments on a proposed marketing policy at any time after it is announced and until 15 days after the date of the last Public Comment Forum. Following the public comment period, the Administrator will modify the allocation policy proposal to the extent he deems appropriate, considering the comments received, and publish the revised proposal in the Federal Register.

DATES: Public Information Forums will be held on the following dates at the locations indicated. At 9 a.m. on October 31, 1979, at the BPA Auditorium, 1002 NE. Holladay Street, Portland, Oregon. At 7:30 p.m. on November 5, 1979, at Mt. Hood Room, Travelodge at the Coliseum, 1441 NE. Second Avenue, Portland, Oregon; and The Forum, Walla Walla Community College, 500 Tausick Way, Walla Walla, Washington. At 7:30 p.m. on November 6, 1979, at Forum R, Eugene Hotel, 222 East Broadway, Eugene, Oregon; and City Council Chambers, 140 South Capitol, Idaho Falls, Idaho. At 7:30 p.m. on November 7, 1979, at Terrace Room A, Ridpath Hotel, West 515 Sprague, Spokane, Washington; and Phoenix C and D Rooms, Hyatt House-Seattle, Sea-Tac International Airport, 17001 Pacific Highway South, Seattle, Washington. At 7:30 p.m. on November 8, 1979, at Colt 44 and 45 Rooms, Outlaw Inn, 1701 Highway 93 South, Kalispell, Montana.

FOR FURTHER INFORMATION CONTACT:

Ms. Donna Lou Geiger, Public Involvement Coordinator, P.O. Box 12999, Portland, Oregon 97212, 503-234-3361, ext. 4261. Toll-free numbers for Oregon callers 800-452-8429; for callers from Washington, Idaho, Montana, Utah, Nevada, Wyoming, and California: 800-547-6048.

Mr. John H. Alberthal, Area Manager, Room 201, 919 NE. 19th Avenue, Portland, Oregon 97208, 503-234-3361, ext. 4551.

Mr. Ladd Sutton, District Manager, Room 206, 211 East Seventh Avenue; Eugene, Oregon 97401, 503-345-0311.

Mr. Ronald H. Wilkerson, Area Manager, Room 561, West 920 Riverside Avenue, Spokane, Washington 99201, 509-456-2500, ext. 2518.

Mr. Gordon H. Brandenburger, District Manager, P.O. Box 758, Kalispell, Montana 59901, 406-755-6202.

Mr. Joseph J. Anderson, District Manager, Room 314, 301 Yakima Street, Wenatchee, Washington 98801, 509-662-4377, ext. 379.

Mr. George A. Tupper, Area Manager, Room 250, 415 First Avenue North, Seattle, Washington 98109, 206-442-4130.

Mr. Harold M. Cantrell, Area Manager, West 101 Poplar, Walla Walla, Washington 99362, 509-525-5500, ext. 701.

Mr. Martin C. Derksema, District Manager, 531 Lomax Street, Idaho Falls, Idaho 83401, 208-523-2706.

SUPPLEMENTARY INFORMATION: Two weeks after the date of publication of this Notice, the major studies and analyses which have been used will be available for review and copying at BPA headquarters located at 1002 Northeast Holladay Street, Portland, Oregon. They are:

1. *Draft* Option Papers Evaluating BPA and Regional Power System Alternatives;
2. *Draft* Allocation Policy Discussion Papers;
3. Direct-Service Industry Impact Study;
4. Computer Listings and Tables;
5. Summary of Public Comment;
6. Skidmore, Owing and Merrill (SOM) Report;
7. Northwest Energy Policy Project (NEPP) Report;
8. NRDC Alternative Scenario.
9. Power Outlook, May 1979.

Environmental impacts of the proposed allocation policy and alternatives will be analyzed in an Environmental Impact Statement (EIS). A Notice of Intent to Prepare an EIS on the Proposed Policy and Formula to Guide Allocation of Firm Electric Energy and System Reserve Energy from the FCRPS will be published in the Federal Register. BPA will solicit public views on the scope of the Draft EIS.

BPA has included Draft Tables and an Exhibit in Part IV of this Notice. They are:

1. *Estimated Net Federal Resources Available for Allocation;*
2. *Basic Load Resource Data;*
3. *BPA Preference Customers' Estimated Firm Energy Requirements,*

Operating Years 1983–84 through 1997–98;

4. *Existing BPA Preference Customers: Estimated System Loads, Calculated BPA Allocations, BPA Obligations, and Utility Deficits, By Year of Contract Expiration;*

5. *Federal Agency Customers of BPA;*

6. *Direct-Service Industrial (DSI) Customers of BPA;*

7. *Comparison of Proposed and Alternative Allocation Policies;* and

8. *Exhibit: Section 22 of the General Contract Provisions attached to Existing Power Sales Contracts.*

The tables contain preliminary or estimated information which is subject to change. Nonetheless, BPA believes the information presented may substantially assist its customers and the public in understanding the proposal and its implications.

I. Proposed Policy and Formula to Guide Allocation of Firm Electric Energy and System Reserve Energy From the FCRPS

(1) *Class(es) of Customer(s) to be Served:*

(a) BPA will accord preference and priority to existing preference customers (customers which now have firm power contracts), new preference customers (customers receiving an allocation during the first year of service), and preference applicants (public bodies and cooperatives which have pending applications). Preference customers will share the firm energy which becomes available for allocation as Direct-Service Industrial (DSI or DSI's) and Federal agency contracts expire or new resources are added to or subtracted from the system which may or may not be anticipated and reflected in BPA's resource data.(*1*)

(b) As their contracts expire, DSI's and Federal agencies may apply to their local utilities for service.

(c) BPA will continue to provide not less than 221 average megawatts (MW) of firm power for use within the State of Montana.(*2*)

(d) BPA will serve any preference applicant which BPA determines is eligible for an allocation and which BPA determines (1) can receive power from BPA in a manner consistent with BPA's policies and practices for the delivery of power to its customers, (2) has acquired or can be reasonably expected to acquire a power supply from non-BPA source(s) sufficient to meet that portion of its load not met by a BPA allocation, and (3) can receive or can be reasonably expected to receive an allocation of energy over its own or other non-Federal facilities, or available BPA facilities.

(2) *Customer-owned assured Resources:* The disposition of customer-owned, non-Federal resources can affect the allocation of Federal power. An amount of assured resources for each customer will be determined for each operating year. The assured resources will reduce the customer's requirements eligible for allocation. The capability of assured resources are determined by a customer's hydrogeneration resource based on adverse streamflows, a customer's thermal-generating resources based on probable or more conservative fuel and generating conditions, and the firm capability of a customer's other resources acquired by contract.

Starting July 1, 1983, BPA will use the existing preference customer's 1975–76 assured resources in determining its base allocation of firm energy. BPA will determine a new preference customer's base allocation assuming its 1975–76 assured resources are zero, unless the new customer has obtained some or all of the resources of another Pacific Northwest utility. For all other allocations prior to July 1, 1991, and all allocations thereafter, any resources an existing preference customer owns or acquires by purchase and uses in its own system, at a resource cost equal to or less than the resource cost of BPA firm energy, will be considered assured resources.

Starting July 1, 1983, BPA will require each customer to either use in its own system any resources which can reasonably be made available to meet its own firm loads, or to make these resources available for purchase at cost including a reasonable rate of return. These resources may be purchased first by BPA, in accordance with existing statutory authorities, for its own use or on behalf of its preference customers, second by BPA's preference customers, and third by other Pacific Northwest utilities. If the customer elects to sell or dispose of these resources in a different manner, then the amount of its BPA allocation will be reduced by the amount of the resources so sold or disposed of.(*3*)

(3) *Type(s) of Load(s) Served:* To calculate the loads eligible for an allocation of BPA firm energy, existing and new preference customers may include all firm loads served (including, but not necessarily limited to, domestic or residential, commercial, industrial, irrigation, and public authorities), except new or expanding single loads which equal or exceed 10 average MW in a 3-year period commencing from the date of initial service, which have not been contracted for or committed to prior to September 1, 1979.(*4*) Those amounts of any loads which BPA or any Pacific Northwest utilities contracted to serve as nonfirm loads prior to September 1, 1979, will be regarded as new or expanding single loads if they become firm loads, e.g., the interruptible and reserve quartiles of the current DSI loads which are considered non-firm. Federal agency loads now served by BPA which will be served by preference customers after existing Federal agency contracts expire may be included as preference customer loads eligible for an allocation.

(4) *Conservation.* BPA believes that conservation should be addressed in the formulation and implementation of any allocation policy. The potential exists for a significant further reduction in regional electric energy usage through conservation. Achievement of feasible and effective conservation through implementation of the proposed BPA allocation policy would serve the public interest by efficiently utilizing and promoting the widespread use of existing and prospective Federal firm energy resources.

BPA will reserve 15 percent of the total firm energy available for allocation to preference customers. Additional allocations will be awarded to preference customers from the conservation reserve as a reward for their individual conservation achievements. To be eligible for an additional allocation from the conservation reserve, each preference customer and each preference applicant must establish a conservation program and implementation plan designed to (a) achieve a phased reduction of at least 15 percent of what its total load would otherwise have been, absent its program, in the 1989–1990 operating year or earlier if reasonably practicable; or (b) to achieve all feasible conservation measures which can be instituted by the customer or applicant (if judged to be less than 15 percent) by the 1989–1990 operating year or earlier if reasonably practicable.(*5*)

An existing preference customer will prepare and submit its conservation program and implementation plan to BPA by January 1, 1982.(*6*) Each preference applicant will submit a conservation program and implementation plan to BPA with its application for an allocation of firm energy. The program must be implemented as soon as reasonably practicable. BPA will review all conservation program/implementation plan submissions to determine the potential energy savings that can be achieved.

If BPA determines that a program under review is capable of achieving a

15 percent savings in the customer's or applicant's forecasted firm energy requirements in the 1989–1990 operating year or sooner, or will achieve all energy savings which are within the customer's capability (if judged to be less than 15 percent); then the customer or applicant will be eligible for an additional allocation of energy. The resulting total allocation will be determined by dividing the product of the allocation formula by 0.85 (see 7. *Duration and Terms of Allocations).*

If BPA considers a proposed program deficient, the customer or applicant may subsequently submit a program amendment to remedy the deficiency in its original program submission. BPA would then provide in the appropriate operating year the additional allocation for which the customer or applicant is eligible. If a customer or applicant fails to develop a program to achieve either a 15 percent savings or the conservation within the customer's capability, then the customer will not be eligible for any allocations of energy from the conservation reserve.

If BPA determines that a customer's program will result in energy savings exceeding the 15 percent goal in any operating year, then the customer's or applicant's total allocation will be increased 1 percent for each 1 percent that the savings exceed 15 percent. This adjustment will be made for the operating year in which the savings are projected to exceed 15 percent. This reward can be allocated during the operating year beginning July 1, 1985, and during any succeeding operating year.

If, after adjusting the allocations for customers which (1) realize 15 percent conservation, and (2) realize greater than 15 percent conservation, some amount of the firm energy reserved for conservation rewards remains unallocated, the Administrator will determine how to dispose of this energy.

BPA is proposing a conservation program requirement, specifying a conservation goal, and prescribing an incentive for individual customers and applicants to attain the goal by providing additional allocations for adequate program design and implementation. However, BPA does not consider it appropriate to prescribe a uniform set of conservation program criteria invariably applicable to all customers and applicants. It will be incumbent upon each customer and applicant to develop and implement a program that is tailored to its individual system characteristics.

BPA will develop and publish its program standards, including evaluation criteria, annual reporting requirements, and program progress review procedures by the time the final allocation policy is promulgated. BPA's program standards may also identify those measures or actions considered conducive to achievement of the desired savings. Upon request, BPA will consult with customers and applicants and assist in the design of programs which could feasibly provide the desired savings.

Each program proposal should identify and provide support for the overall savings projected. The program proposals may include preexisting and proposed new conservation measured as well as measures required by others which could result in electric energy savings. Each customer or applicant must provide assurances that the measures will be implemented at the earliest possible date, and that each measure can reasonably be expected to achieve the specific savings associated with it. BPA and the customer will jointly evaluate individual program progress annually.

Beginning July 1, 1983, BPA will provide annual notice to its customers of the adjustments for conservation which will result in a change to the customers' allocations simultaneously with their allocations for the operating year 2 years hence. Full allocations will be made in OY's 1983 and 1984 assuming good faith efforts to conserve and the adoption of sound programs by BPA customers.

On January 1, 1984, and each year thereafter, each customer will submit a progress report and may submit a program and/or plan amendment. However, program and plan amendments may be submitted at any time. Beginning July 1, 1985, BPA will expect to have observed tangible progress. BPA will also expect its customers to show evidence of progress each operating year thereafter, and to sustain their conservation efforts throughout the contract period. BPA will not make any allocations from the conservation reserve for the appropriate operating year to customers who discontinue their program or fail to achieve the desired savings.

(5) *Load Determinations and Resource Availability:* BPA will review and approve all estimates of the firm energy requirements of customers and applicants for the purpose of allocating BPA firm energy.(7) BPA will use the customers' and applicants' net firm energy requirements to determine their allocations. Net firm energy requirements are a customer's or applicants' total system firm energy load less its assured resources (see (2) *Customer-Owned Assured Resources).*

Starting July 1, 1982, and on each July 1 thereafter, BPA will provide annual projections of the aggregate FCRPS firm energy resources available for allocation, by operating year, for the 10-year period ahead. These annual projections will represent BPA's minimum firm energy obligation for each operating year within the rolling 10-year period.

(6) *System Reserves.* BPA presently markets to the DSI's a block of energy providing the FCRPS with both capacity and energy reserves. This block of energy accounts for approximately 25 percent of DSI load (the second quartile). BPA makes use of these system reserves by restricting deliveries to the DSI's when it is necessary to protect BPA's firm energy commitments to its preference customers. They are also used to the extent that BPA is committed to back up a preference customer's own generation. BPA exercises its restriction rights directly through BPA-controlled load-control devices.

BPA believes that system reserves are needed even after the current DSI contracts expire. These needs include both BPA requirements and those of preference customers who wish to contract for their own specific reserve requirements.

The system reserve energy will be made available to preference customers with BPA retaining rights to restrict deliveries for its own and contract purposes. On July 1, 1982, and every July 1 of succeeding operating years, BPA will estimate the amount of this system reserve energy that will be made available for sale 2 operating years hence. Initially, the amount will equal about 25 percent of the total DSI contract demand specified in the contracts which have expired by the given operating year. If BPA determines that the amount of system reserves that will be needed for forced outages and other purposes must be changed, BPA will make an equivalent change in the amount of firm energy available for allocation.

The system reserve energy will only be made available to preference customers who can use such energy for their loads and who agree to provide BPA with contract rights to: (a) restrict deliveries to satisfy either capacity or energy (or both) reserve requirements, and (b) permit BPA to restrict loads directly with BPA-controlled load-control devices. If the BPA supply of system reserve energy is not sufficient to meet the needs of all customers, then each customer may purchase pro rata shares of the available system reserves.

BPA recognizes that many preference customers may not directly serve loads suitable for restriction. All customers should be able to directly share in the economic advantage of the reserve energy with other preference customers who serve such loads. Because it would be administratively infeasible to allocate system reserves to all customers in proportion to their net requirements and provide for the many complex, multiparty rate and operating contracts to implement an equitable sharing of system reserves, BPA will establish a special higher rate for this system reserve energy so that the benefits will accrue to all customers through lower BPA firm energy rates. This system reserve rate will be generally based on the average wholesale power costs of all preference customer resources, including purchases from BPA, used to meet firm loads with adjustments for the value of system reserves provided either in the average rate or in rate credits, if any, if deliveries of such energy are restricted. Such rates will be established as a normal part of BPA rate proceedings.

(7) *Durations and Terms of Allocations:* All BPA allocations of firm energy and all estimates of system requirements are subject to the adjustments for energy conservation described under (4) *Conservation.*

BPA will offer to contract to supply the net firm energy requirements of computed demand customers and the requirements, including contract demands of all other existing preference customers, subject to limitations on obligations to serve large new loads and the right to restrict power delivery obligations on proper notice. All contracts will contain allocation provisions to implement the final policy when promulgated. These provisions will take effect July 1, 1983, or later, depending on the date of execution of the contract. They terminate July 1, 2001.

Preference applicants who otherwise qualify may also receive an allocation if they apply to BPA after the final policy is promulgated and 30 months or more before firm energy and system reserve energy are scheduled to become available as a result of contract expirations, resource additions, or any operating year after July 1, 1991, when allocations are revised for all preference customers.

BPA will use the following formula for determining the allocations to preference applicants and the allocations to existing and new preference customers:

Allocation Formula

BPA will determine the amounts of (A/B)(C) and (D) for each customer.

A customer's total allocation, prior to any additional allocations for conservation and adjustments for sharing of benefits and costs, will equal:

(1) (D), limited to the customer's net requirements, for those customers where (D) is greater than their respective (A/B)(C) amounts.

(2) For all other customers, the pro rata share of the firm energy, based on net requirements, which remains available for allocation after deducting the total amount allocated under (1) above, from the total amount available for allocation (C). However, the pro rata share will not be less than a customer's (D), limited to that expressed in average megawatts.

A=Customer's total net firm energy requirements.
B=Total of all customers' net firm energy requirements.
C=Total amount of firm energy BPA has available for allocation or has allocated, less the 15 percent reserved for conservation incentives.
D=The allocation of the customer adjusted by a factor of 0.85 for conservation. For all customers, the value of "D" becomes zero as of July 1, 1991. An existing preference customer's base allocation prior to July 1, 1991, and a new preference customer's base allocation during the first year of service prior to July 1, 1991, will be computed in accordance with the provisions of this section.

To determine the base allocation for its existing preference customers, BPA proposes to continue the terms of Section 22 of the General Contract Provisions attached to its current firm power sales contracts in the new contracts to be offered existing preference customers. However, this base will be adjusted for the conservation reserve by multiplying by a factor of 0.85. The allocation can be increased for achievements in energy conservation as provided under (4) *Conservation.*

Except for the City of Tacoma and those existing preference customers formerly served by the city of Tacoma which have, contracts with provisions containing modified allocations, each existing preference customer's allocation under Section 22 consists of:

(a) *a hydro allocation* based on 1975–76 actual system firm energy requirements less assured resources. However, if this results in a net firm energy requirement that is less than 25 average MW, then the customer will recieve a hydro allocation not to exceed 25 average MW;

(b) *a thermal allocation* which is equal to a fraction whose numerator is *the lesser* of *either* actual load growth from OY 1975–1976 through OY 1982–1983, or 103 percent of the forecasted load growth, as of December 1973, for the same period *divided* by the total load growth of all existing preference customers for the same operating period (OY's 1975–76 through 1982–83) but *limited* for each customer to 103 percent of the December 1973 load forecast and *multiplied* by a factor of 1881.8 MW. (This factor was determined from BPA's 30 percent share of the Trojan nuclear plant, BPA's 100 percent shares of WPPSS #1 and #2 plants, and BPA's 70 percent share of WPPSS #3 plant (or WNP #1, #2, and #3). If the city of Eugene withdraws any power from Trojan, or if BPA acquires power from any additional net-billed thermal projects, the 1881.8 MW is subject to change.)

(c) A third allocation exists for 37 participants in the Canadian Entitlement Exchange Agreement. Under this allocation, BPA will provide annually an amount of energy equal to the difference between each participant's 1983–84 share of Canadian Storage Power Exchange (CSPE) energy and the shares available to each participant for each succeeding year through the life of the CPSE Agreement.

From July 1, 1983, through June 30, 1991, new preference customers as a group will be eligible for base allocations, adjusted by multiplying by a factor of 0.85 for conservation, from up to two-thirds of the firm energy which becomes available for allocation or reallocation due to contract expirations or an increase in the total resources available for allocation during the operating year in which they first receive service. However, a new preference customer's base allocation during the first year of service cannot exceed the ratio of all preference customer's allocations to their aggregate net firm energy, requirements.

BPA anticipates that there will be a transition in the allocation process until July 1, 1991. From that date forward, BPA will allocate energy on the basis of the relationship of each customer's total net firm energy requirements to all customers' total net firm energy requirements multiplied by the total amount of power BPA has available for allocation, less the 15 percent reserved for conservation rewards. The allocation can be increased for achievements in energy conservation, as provided under (4) *Conservation.*

BPA recognizes that an existing preference customer may elect to continue to purchase firm energy from BPA on the basis of its current contract until its expiration, and not to sign the new contract offered. If so, the customer will be entitled only to its allocation as determined under it current contract until expiration. Should the customer apply to continue purchasing firm energy from BPA prior to or at the time of contract expiration, it will be regarded as a preference applicant. As a perference applicant it will be accorded the same rights to available resources as other preference applicants. Following contract expiration, being a former BPA preference customer will not establish a special priority for BPA firm energy. The energy available from this customer's contract will be treated in an identical fashion to the energy available from an expired Federal agency or DSI contract.

The preference applicant's allocations will be held to serve them no more than 5 years following the date of application, if they are unable to accept service as anticipated. Subsequently, any such unused allocations will be made available to preference customers.

On July 1, 1982, BPA will allocate firm energy for the operating year commencing July 1, 1984. On July 1 of each operating year thereafter, BPA will notify its customers what their allocations of BPA firm energy will be 2 operating years hence.

(8) *Sharing of Benefits and Costs.* The allocation formula assures each preference customer and applicant a share of the available BPA firm energy to meet some portion or all of its system firm energy requirements. In addition, knowing what the base allocation will be, the total amount to be allocated, and how the allocation formula works gives customers and applicants a greater sense of certainty and some basis for planning conservation efforts and resources acquisitions.

Prior to July 1, 1991, allocations are not calculated on a pro rata basis. Therefore, the allocations do not reflect a full sharing of the economic benefits and costs of BPA firm energy among BPA customers. Another feature of the proposed policy assures that the sharing of benefits and costs will more closely approximate what would otherwise be the case after July 1, 1991, when all customers will receive pro rata allocations. This feature may cushion the change which would otherwise occur at that time by providing for a transition adjustment to the extent the new contracts permit:

(a) BPA will determine each customer's calculated pro rata share of the total BPA allocation (on the basis of (A/B)(C), adjusted for conservation, as appropriate).

(b) BPA will determine which customers will receive allocations that fall shy of their calculated pro rata shares and which customers would receive allocations that exceed their calculated pro rata shares.

(c) Those customers which require an increase in their allocations to meet their calculated pro rata shares may provide amounts of energy (offset energy) equal to their individual shortfalls to BPA at the average wholesale cost of their firm energy, which includes their allocations from BPA. In exchange, BPA would provide equivalent amounts of BPA firm energy to these customers.

(d) Those customers whose allocations exceed their calculated pro rata shares will receive firm energy in amounts equivalent to the allocations. The equivalent amounts would be comprised of an allocation of BPA firm energy equal to each customers's pro rata share of its allocation and the remainder which will be supplied from the offset energy received. These customers will pay for this offset energy at the average rate for all offset energy, and will pay for BPA energy, at BPA's rates.

(9) *Minimum Allocation. (8)* The minimum allocation provision, adjusted for conservation, will be included in the new contracts offered to existing preference customers and will be effective through June 30, 1991. It will not be available to new preference customers.

(10) *Grades of Power.* The BPA allocations policy applies to firm energy and system reserve energy only.

(11) *Rates.* BPA considers wholesale power rates a separate policy matter. However, future ratemaking would be affected if certain features of the proposal are eventually adopted.

Footnotes

1. Approximately 2900 average MW and 200 average MW of firm energy is currently committed by contract to DSI's and Federal agencies, respectively. New resource additions may become available as facilities not now in planning or construction are installed in existing Federal hydroelectric projects, or additional net-billed power is generated at plants presently under construction. The known new resource additions are reflected in the data on projected resources available for allocation.

2. This policy determination reflects the geographic preference contemplated by the Hungry Horse Dam Act of 1944 (43 U.S.C. 593a).

3. This should permit BPA to control the disposition of its resources, since it would discourage any preference customer from utilizing lower cost BPA energy in its system while selling its resources at profit, to the detriment of BPA and its other customers within the region.

4. Historically, BPA has sold power to the utilities without regard to the end uses served. BPA has complied with the mandatory provisions of the Bonneville Project Act to give preference and priority to public bodies and cooperatives. The Act also refers to the desirability of operating the generating facilities for the benefit of the general public, "* * * and particularly of domestic and rural consumers, * * *" but it does not restrict service to that type of load. BPA considers that Domestic and rural consumers have benefitted from its historical power marketing policies. The availability of low-cost Federal energy to serve multiple end uses has been one of a number of factors conducive to regional economic development.

5. The 15 percent targeted savings is partly based upon BPA's review of recent studies of potential conservation savings in the region, including the Skidmore, Owing and Merrill (SOM) Report July 1976 commissioned by BPA, and the 1977 conservation study prepared for the Northwest Energy Policy Project (NEPP) commissioned by the Northwest Governors. BPA has also considered the concepts in the "Alternative Scenario" proposed in January 1977 by the Natural Resources Defense Council (NRDC) for inclusion in BPA's Role EIS.

The findings of these studies vary:

(a) SOM foresees potential conservation savings of 33 percent by 1995 resulting from adoption of conservation programs ranging from moderate information and education efforts to strong mandatory measures and technologies not yet widely available;

(b) NEPP foresees potential conservation savings of 33 percent by 2000. However, it proceeds from a much lower consumption level, so all its curves fall below the SOM curves. NEPP's econometric model assumes higher energy prices and translates the effects of those prices into lower energy consumption.

The NRDC "Alternative Scenario" foresees potential conservation savings and changes in the region's industrial mix, postulating that only 4 of the 13 power generating facilities presently scheduled for completion between now and 1990 will actually prove to be needed by 1995. The "Alternative Scenario" does not specifically address needs after 1995.

BPA believes that the achievable energy savings through utility programs *may* be about one-half the maximum *potential* total savings identified in the NEPP and SOM studies. BPA is also looking at a target year of 1990, rather than 1995 or 2000. A regional and individual utility goal of 15 percent conservation savings by 1990 through existing and new programs is ambitious, but necessary and achievable. However, BPA recognizes that individual utility accomplishments may vary.

6. The allocations become effective July 1, 1983. Eighteen months should be sufficient for BPA to review the customers' and applicants' program proposals and for customers and applicants to develop and submit alternatives should BPA find the initial submission(s) deficient.

7. For policy analysis purposes, BPA has utlized data on loads and resources published in the 1979 PNUCC Blue Book of, for the East Group Utilities, data submitted to BPA in 1978.

8. The minimum allocation is not a statutory requirement. It was originally designed to meet *future* load requirements experienced by small preference customers unable to attract the necessary financing to develop their own energy resources and to assist the development of utilities to serve rural areas.

II. Public Meetings

A. *Public Information Forums.* BPA will conduct eight public information forums for its customers, consultants, and other interested groups and individuals. The forums will be educational in nature and will be designed (1) to explain the proposed allocation policy and supporting analyses and (2) to answer questions. Questions raised at the forums will be answered at that time, if possible, or in writing at a later date. The meetings will be held at the following locations and on the dates specified:

BPA Auditorium, 1002 NE. Holladay Street, Portland, Oregon, 9 a.m., October 31.

Mt. Hood Room, Travelodge at the Coliseum, 1441 NE. Second Avenue, Portland, Oregon, 7:30 p.m., November 5.

The Forum, Walla Walla Community College, 500 Tausick Way, Walla Walla, Washington, 7:30 p.m., November 5.

Forum R, Eugene Hotel, 222 East Broadway, Eugene, Oregon, 7:30 p.m., November 6.

City Council Chambers, 140 South Capitol, Idaho Falls, Idaho, 7:30 p.m. on November 6.

Terrace Room A, Ridpath Hotel, West 515 Sprague, Spokane, Washington, 7:30 p.m., November 7.

Phoenix C and D Rooms, Hyatt House-Seattle, Sea-Tac International Airport, 17001 Pacific Highway South, Seattle, Washington, 7:30 p.m. November 7.

Colt 44 and Colt 45 Rooms, Outlaw Inn, 1701 Highway 93 South, Kalispell, Montana, 7:30 p.m., November 8.

The meeting scheduled for 9 a.m. on Wednesday, October 31, in Portland will be more technical than the other meetings. The purpose of that meeting is to discuss the proposed allocation policy in greater detail.

B. *Procedure.* The meetings will be conducted by a chairperson who will be responsible for an orderly process. Each meeting will be recorded. The transcripts and questions and written answers will become part of the Official Record. The Record will be available for review and copying at BPA headquarters, 1002 Northeast Holladay Street, Portland, Oregon.

C. *Public Comment Forums.* Public Comment Forums to permit the public to submit oral comments regarding the proposed allocation policy will be scheduled in 1980 when the draft Environmental Impact Statement is available.

Written comments on the proposed allocation policy may be submitted to BPA at once. The written comments will become part of the Official Record and will be considered in the final allocation policy that will be developed by BPA. These comments should be submitted to the Public Involvement Coordinator, Bonneville Power Administration, P.O. Box 12999, Portland, Oregon 97212.

III. Glossary of Terms

An *allocation policy* is a plan to distribute the firm energy available for marketing from the FCRPS among BPA customers. The term "firm energy" includes energy from hydro, thermal, and other resources.

An *allocation formula* is a mathematical formula used to calculate the amount of firm energy which will be allocated to each qualified customer eligible for an allocation.

An *assured resource capability* means the capability of a customer's hydrogeneration resource based on adverse streamflows; the capability of a customer's thermal-generating resources based on probable or more conservative conditions; and the firm capability of other resources acquired by contract.

An *average megawatt (MW)* is a measure of average power over a given time period. To determine the average megawatts, divide the total megawatt hours measured in the time period by the number of hours in the period, e.g., if 10 megawatt hours of electric energy are measured over a 5-hour period, then 2 average megawatts would be the average rate at which power is delivered.

A *base allocation* is the fixed portion of a total allocation over a given time period. The remaining portion of an allocation, if any, may vary in amount depending on the availability of resources in excess of the aggregate base allocations.

The *Bonneville Project Act* is a statutory enactment (i.e., passed by Congress and signed into law by the President in 1937) to create the Bonneville Power Administration.

The *Bonneville Power Administration* (BPA or Bonneville) is an agency within the Federal Department of Energy. BPA was created to market the power produced by dams on the Columbia River.

Capacity refers to the amount of system power which can be supplied at any instant in time. It is usually measured over a 60-minute period. Capacity is expressed in terms of watts (kilowatts or megawatts for convenience). For example, if the maximum output from three resources is 100 megawatts each, the total capacity is 300 megawatts (300,000 kilowatts, or 300,000,000 watts).

Conservation means any reduction in energy consumption as a result of increases in the efficiency of energy use, production or distribution.

Critical period means that multimonth period, determined under the Pacific Northwest Coordination Agreement for adverse steamflows of historical record adjusted for changes in consumptive uses. The Coordinated System is comprised of the generating resources of the utilities who are parties to the Pacific Northwest Coordination Agreement. This agreement provides for the coordinated operation of the Columbia River and tributaries to maximize generation within other constraints. During the critical period the *least* amount of Estimated Firm Energy Load can be served from the Firm Resources of the parties to the Coordination Agreement. There are a number of consumptive uses which a dam with generating facilities may serve, e.g., municipal and industrial water supply or water for irrigation may be obtained from the water held in storage behind a dam.

Customer classes refer to the classes of customers BPA serves. They include preference customers, Federal agencies, direct-service industries, and investor-owned utilities.

Demand is a requirement for capacity. Demand results from electrical loads. Capacity refers to the ability of a system to produce sufficient power to meet customer loads (demands).

A *direct-service industrial customer (DSI)* is an industrial consumer who purchases energy directly from BPA. BPA presently has contracts with 17 DSI's.

DSI quartiles refer to the four blocks of energy sold to the DSI's. The first quartile (top) is energy which BPA may restrict for any reason or which DSI's may curtail for any reason. The second quartile (second from top) is energy which may be restricted by BPA to serve firm loads if and when delays occur in the construction of additional power plants, which, in turn, cause a shortage of firm energy to serve firm loads or when a forced outage occurs. The third and fourth quartiles (third and fourth from top) are firm power that BPA is committeed to serve without interruption except for 5 minutes of interruption to maintain system stability. Half the load operating at any given time may be restricted by BPA, if necessary, because of forced outages of generating equipment.

Electric power is the rate at which electric energy is being used to do work. Electric power is expressed in watts.

Electric energy is the amount of electricity which is consumed in doing a certain amount of work. Electric energy is equal to electric power (watts) multiplied by time (hours). Electric energy is expressed in kilowatthours or megawatthours.

End use refers to the kind of use to which the ultimate consumer puts the electric energy purchased. End uses are usually expressed in terms of the class of ultimate consumer of the electric energy: e.g., industry, commercial, residential or domestic, irrigation, or public authorities.

An *energy reserve* is a supply of electric energy which is held in reserve to meet a forced outage of a generator or a shortage. Reserves can be sold subject to restriction in order to continue meeting firm loads.

An *environmental assessment (EA)* is a documented analysis performed to determine if any significant environmental impacts may result from a proposed Federal action, and provide a basis for deciding whether an environmental impact statement is needed. An EA may be prepared to comply with the National Environmental Policy Act (NEPA, P.L. 91–190).

An *environmental impact statement (EIS)* is a documented analysis required by NEPA whenever a Federal agency proposes to take an action which would significantly affect the environment. An EIS must identify the proposed action and reasonable alternatives and provide comparative analysis of the environmental impacts of the proposed action and each alternative.

The *Federal Columbia River Power System (FCRPS)* refers to the Federal system of power dams and interconnecting transmission facilities located on the Columbia-Snake Rivers and tributaries in the Pacific Northwest and other resources acquired by BPA.

Firm energy means electric energy which is to be continuously available to the customer during a specified period to meet all or any agreed upon portion of the customer's electrical requirements, except capacity.

Firm power is a source of power which should be dependable under adverse conditions.

A *forced outage* is an interruption to service because of a reduced supply of electric power from a generating source or an inability to deliver power because of a transmission facility failure.

A *hydro resource* is a source of electricity which is derived from power produced by running water through turbines.

The *Hydro Thermal Power Program (HTPP)* was a program to obtain thermal generating resources in the Pacific Northwest region and integrate the thermal power with hydropower in order to supplement the Federal resources available for marketing.

An *interruptible load* is a load which can be temporarily interrupted when power is needed elsewhere in the system when a capacity or energy deficiency occurs. An interruptible load exists through contractual arrangements between a utility and its customer.

A *load* is the demand for electric power by a customer.

A *kilowatt* is a unit of power equal to 1,000 watts.

A *kilowatthour* is a unit of energy equal to 1 kilowatt for 1 hour.

A *megawatt* is a unit of power equal to 1,000,000 watts.

A *megawatthour* is a unit of energy equal to 1,000,000 watts for 1 hour.

A *minimum allocation* is a 25 MW fixed amount of firm energy which is reserved for specific preference customers. The minimum allocation is to meet future load growth experienced by small preference customers who might have difficulty financing or acquiring new energy resources.

Plant capacity factor is the ratio of energy actually produced at a generating plant to the energy that could have been produced under 100 percent operating conditions. E.g., a plant capacity factor of 0.50 (or 50%) means a plant actually produced half of the energy it ideally could have at full operation over the specific period of time.

A *power sales contract* is a contract instrument for the sale of BPA power to a customer.

Preference clause refers to that section of the Bonneville Project Act which granted statutory preference and priority for BPA's power to public bodies and cooperatives. The preference clause has been restated in a number of other statutes.

A *preference customer* is a customer who has a statutory right to preference and priority in the purchase of BPA firm energy and who is receiving power from BPA. Under law, preference customers must be public bodies or cooperatives.

Public bodies and cooperatives are BPA preference customers. The Bonneville Project Act of 1937 defines a "public body" or "public bodies" as states, public power districts, counties, and municipalities, including their component agencies or subdivisions. A "cooperative" or "cooperatives" means any form of non-profit-making organization(s) of citizens supplying, or created to supply, members with goods, commodities, or services, as nearly as possible at cost.

Requirements refer to the amount of electric power or energy associated with the electrical load.

Reserves means a portion of total generating capability planned to be available to serve loads in case of forced outages or unanticipated load growth.

Resources are the sources from which electric power and energy are produced. Resources include generating plants (nuclear, coal, hydro), purchase agreements, and conservation measures.

A *thermal resource* is a source of electricity which uses thermal energy (heat) to produce electricity. Usually thermal resources refer to natural gas, diesel, coal, nuclear power, oil, or biomass generating equipment.

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Table I

ESTIMATED NET FEDERAL RESOURCES AVAILABLE FOR ALLOCATION
AVERAGE FIRM ENERGY IN MEGAWATTS 1/
BY OPERATING YEAR 2/

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Resources															
1. Total Federal Hydro	7773	7765	7729	7731	7736	7722	7669	7664	7660	7656	7651	7647	7644	7643	7639
2. Federal Imports	358	358	358	206	20	-	-	-	-	-	-	-	-	-	-
3. Net-billed Thermal	1445	2004	2432	2490	2490	2490	2490	2490	2490	2490	2490	2490	2490	2490	2490
4. Total Resources	9576	10127	10519	10427	10246	10212	10159	10154	10150	10146	10141	10137	10134	10133	10129
Commitments															
5. Exports	97	99	101	103	105	108	111	108	108	108	108	108	108	108	108
6. Contracts Out	289	289	289	289	289	289	289	277	277	277	277	277	277	277	277
7. CSPE	488	462	437	412	387	363	344	327	315	302	289	276	264	252	238
8. Hydro Maintenance	32	33	33	34	34	34	34	34	34	34	34	51	51	51	51
9. USBR Reserve Power	63	69	77	80	80	83	88	91	92	92	93	95	96	96	96
10. Firm Losses	378	374	353	345	357	371	384	410	416	435	454	473	491	503	523
11. Montana Reservation	221	221	221	221	221	221	221	221	221	221	221	221	221	221	221
12. Sub-Total	1568	1547	1511	1484	1473	1469	1471	1468	1463	1469	1476	1501	1508	1508	1514
13. Industrial Contracts	2855	2622	2484	1595	370	83	83	6	1	-	-	-	-	-	-
14. Federal Agency Contracts	167	101	45	47	49	49	51	1	1	1	-	-	-	-	-
15. Total Federal Commitments	4590	4270	4040	3126	1892	1601	1605	1475	1465	1470	1476	1501	1508	1508	1514
16. System Energy Reserves to be Provided by:															
(a) DSI Contracts	957	880	834	536	125	28	28	2	----	----	----	----	----	----	----
(b) PC Contracts	8	85	131	429	840	937	937	963	965	965	965	965	965	965	965
17. Estimated Net BPA Resources Available For Allocation 3/	4978	5772	6348	6872	7514	7674	7617	7716	7720	7711	7700	7671	7661	7660	7650

Source of basic data is Pacific Northwest Utilities Conference Committee (PNUCC) Report on Long-Range Projection of Power Loads and Resources for Resource Planning, April 23, 1979

1/ Average megawatts are determined by dividing megawatthours by the number of hours in a specific period (in this case, an operating year).
2/ July 1 - June 30
3/ Estimated net BPA resources available for allocation will be reduced by 15 percent to establish a conservation reserve.

Bonneville Power Administration
September 19, 1979

DRAFT

EXPLANATION OF LINE ITEMS
FOR TABLE I

Line No.

1. Total Federal hydro resources include the hydro resource obligations of Federal and non-Federal projects to Canadian Storage Power Exchange (CSPE) and the Packwood Generation to reflect the Packwood project exchange agreements.

2. Reflects energy imports from the peak/energy exchange contracts with Pacific Southwest utilities and Montana Power Company.

3. Net-billed Thermal is public agencies' shares of Trojan and Washington Public Power Supply System's projects Nos. 1, 2, and 3, computed on the basis of 60 percent plant factor for first year of operation and 70 percent plant factor thereafter.

4. Sum of lines 1 through 3.

5. Exports include BPA's obligations to Montana Power Company for geographic preference, Hanford exchange agreement, wheeling payments, share of WNP #1 beginning July 1980, and Montana Power Company's share of restoration from the West Group Area as per Pacific Northwest Coordination Agreement.

6. Contracts out are the Federal obligations to the private utilities for headwater storage payments and WNP #1 allocations through June 30, 1996, deliveries to Clark and Snohomish County Public Utility Districts (PUD's) and other public agencies associated with Packwood exchange agreement.

7. CSPE obligation to individual private utilities and public agencies for contract purchases from the CSPE resources included under line 1.

8. Estimated hydro reduction due to maintenance required in the critical storage drawdown period.

9. Irrigation pumping requirements from power statutorily reserved for irrigation from United States Bureau of Reclamation (USBR) Federal projects authorized by Congress.

10. Estimated transmission line losses on the Federal System associated with serving firm loads.

11. Montana Reservation is the power reserved for sale within the State of Montana in accordance with the Hungry Horse Dam Act of June 4, 1944, as amended.

12. Sum of lines 5 through 11.

13. Industrial contracts are direct service contracts which will not be renewed upon expiration.

14. Net requirements of the Federal agencies until expiration of all contracts. Excludes 11 average megawatts of U.S. Bureau of Indian Affairs' own generation.

15. Sum of lines 12, 13, and 14.

16. System Energy Reserves to be provided by:

(a) DSI contracts - outstanding contracts with industry which provide for restriction of 2nd quartile.

(b) P.C. contracts - contracts with preference customers which will allow BPA to restrict energy deliveries.

17. Line 4 minus line 15 and line 16(b) combined.

Table II

BASIC LOAD-RESOURCE DATA

EXISTING PREFERENCE CUSTOMERS (PC), BPA, DSI AND FEDERAL AGENCIES
AVERAGE FIRM ENERGY IN MEGAWATTS 1/
BY OPERATING YEAR 2/

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998 3/
1. Net BPA Resources Available 4/ (Line 17, Table I)	4978	5772	6348	6872	7514	7674	7617	7716	7720	7711	7700	7671	7661	7660	7650
2. PC System Requirements	7495	7793	8108	8431	8759	9095	9445	9818	10206	10616	11033	11466	11921	12400	12895
3. 1975-76 PC Assured Resources	1146	1146	1146	1146	1146	1146	1146	1157	1157	1157	1157	1833	2006	2009	2012
4. PC Net System Req'mts. Line 2 minus Line 3	6349	6647	6962	7285	7613	7949	8299	8661	9049	9459	9876	9633	9915	10391	10883
5. BPA Base Allocation to PC	5792	5843	5890	5937	5981	6022	6059	6091	6122	6149	6174	1553	---	---	---
6. PC Additional Req'mts. Line 4 minus Line 5	557	804	1072	1348	1632	1927	2240	2570	2927	3310	3702	8080	9915	10391	10883
7. Remaining BPA Resources 4/ Line 1 minus Line 5	(814)	(71)	458	935	1533	1652	1558	1625	1598	1562	1526	6118	7661	7660	7650
8. Unassigned PC Resources															
Centralia	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
WNP 4	---	62	760	875	875	875	875	875	875	875	875	875	875	875	875
WNP 5	---	---	56	679	781	781	781	781	781	781	781	781	781	781	781
Boardman	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
a. SUBTOTAL LARGE THERMAL	294	356	1110	1848	1950	1950	1950	1950	1950	1950	1950	1950	1950	1950	1950
b. Small Thermal	35	35	34	34	34	34	34	34	34	34	34	8	---	---	---
c. Other Hydro	504	526	543	555	579	597	605	611	623	631	638	162	---	---	---
d. TOTAL UNASSIGNED RES.	833	917	1687	2437	2563	2581	2589	2595	2607	2615	2622	2120	1950	1950	1950
9. DSI Expired Contracts															
a. 3 Quartile Load	---	231	349	1117	2144	2432	2432	2432	2432	2432	2432	2432	2432	2432	2432
b. 2 Quartile Load	---	155	233	709	1324	1516	1516	1516	1516	1516	1516	1516	1516	1516	1516
c. 35 MW Peak Limit	---	41	63	196	369	448	448	448	448	448	448	448	448	448	448
10. Federal Agency (FA) Loads															
a. Total Net Requirements	184	187	190	193	196	198	201	204	207	209	212	216	219	222	226
b. Net Requirements - FA's with Expired Contracts 5/	17	86	145	146	147	149	150	203	206	208	212	216	219	222	226
c. Net Req'mts. - FA's under 10b in PC Service Areas 5/	---	53	108	108	108	110	110	146	148	151	155	158	162	165	169
d. 35 MW Peak Limit	---	30	61	61	61	63	63	83	83	83	84	84	84	84	84
11. a. Assumed New PC Net Requirements	500	525	549	575	600	635	665	700	730	765	800	840	880	925	970
b. Assumed New PC Net Requirements	1500	1570	1650	1725	1800	1900	2000	2100	2200	2300	2410	2520	2640	2770	2910
c. Assumed New PC Net Requirements	3000	3150	3300	3450	3600	3800	4000	4190	4390	4600	4820	5050	5290	5540	5810

Source of basic data is Pacific Northwest Utilities Conference Committee (PNUCC) Report on Long-Range Projection of Power Loads and Resources for Resource Planning, April 23, 1979

1/ Average megawatts are determined by dividing megawatthours by the number of hours in a specific period (in this case, an operating year).
2/ July 1 - June 30
3/ Projections are available through 1998 only.
4/ Amounts shown will be reduced by 15 percent to establish a conservation reserve.
5/ Cumulative totals

Bonneville Power Administration
September 19, 1979

DRAFT

Explanation of Line Items
For Table II

Line No.

1. - BPA Resources less Commitments to Direct-Service Industries (DSI's), Federal agencies, as well as State of Montana's power reservation.

2. - Total load for existing preference customers from 1979 PNUCC Blue Book less Chelan County PUD's Colockum load.

3. - Preference customer assured resources in 1975-76 as used in determining hydro allocations under existing contracts.

4. - Line 2 minus line 3.

5. - BPA allocations to existing preference customers. These allocations are based on the assumption that all existing PC's will sign new contracts containing allocation provisions identical to those in their current contracts but which are valid through September 20, 1994 in all cases (under the status quo, the last of the current contracts with existing PC's expires September 20, 1994).

6. - Line 4 minus Line 5.

7. - Resources which become available to BPA as existing DSI and Federal agency contracts expire, less BPA commitments.

8. - Additional hydro resources available to preference customers not included in line 3. The sum of line 3 plus line 8d equals 1979 Blue Book resources of preference customers.

9. - Loads of DSI's located within or adjacent to preference customers' service areas and whose BPA contracts have expired.

(a) and (b). The amount of industrial firm energy load based on 2 or 3 quartiles.

(c) The amount of industrial load eligible for allocation limited to the energy related to 35 MW peak.

10. - Federal agencies loads reflecting Flathead Indian irrigation district load (U.S. Bureau of Indian Affairs).

(a) Total net requirements of Federal agencies served by BPA.

(b) Net requirements of Federal agencies whose contracts have expired.

(c) Net requirements of Federal agencies located within or adjacent to preference customer service areas and whose contracts with BPA have expired.

(d) Federal agencies' loads limited to 35 megawatts of peak located within or adjacent to preference customer service area.

11. - Estimated levels of new preference customer net firm energy requirements.

Table III

BPA PREFERENCE CUSTOMER'S ESTIMATED FIRM ENERGY
REQUIREMENTS FOR JULY-JUNE OPERATING YEARS
1983-84 THROUGH 1997-98 1/
AVERAGE MEGAWATTS

Sheet 1 of 4

LARGER CUSTOMERS	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Large Municipals															
Eugene, Oregon	301.3	311.0	320.3	328.9	338.0	347.1	356.6	365.8	373.9	382.5	391.3	400.0	408.3	416.1	423.8
Idaho Falls, Idaho	69.5	73.2	77.2	81.3	85.7	90.3	95.1	100.2	105.5	111.0	116.8	122.8	129.1	135.6	142.4
McMinnville, Oregon	41.8	43.1	44.5	45.9	47.3	48.8	50.4	52.0	53.6	55.3	57.2	59.0	60.9	62.9	64.9
Port Angeles, Washington	106.8	108.3	109.4	111.3	113.0	114.8	116.7	118.7	120.7	122.8	125.0	127.3	129.7	132.2	134.8
Richland, Washington	92.0	93.3	94.5	95.0	95.4	95.9	96.4	97.0	97.4	98.0	98.5	99.1	99.6	100.1	100.7
Seattle, Washington	1110.8	1136.7	1162.3	1185.2	1211.9	1233.5	1238.5	1251.8	1272.5	1290.9	1307.2	1321.2	1334.3	1347.1	1357.4
Springfield, Oregon	119.7	123.6	127.6	131.9	136.4	141.1	146.0	151.1	156.3	161.8	167.5	173.4	179.5	185.9	192.5
Tacoma, Washington	660.2	681.0	702.2	723.4	745.1	766.9	788.9	811.2	834.1	857.2	880.9	905.3	930.0	955.4	981.2
Total Large Municipals	2502.1	2570.2	2638.0	2702.9	2772.8	2838.4	2888.6	2947.8	3014.0	3079.5	3144.4	3208.1	3271.4	3335.3	3397.7
Large PUD's															
Benton Co. PUD #1	227.3	241.5	257.2	274.7	293.7	314.1	336.5	358.3	378.5	400.7	424.8	451.2	480.0	511.4	545.8
Central Lincoln PUD	170.8	177.4	182.5	187.7	193.2	198.8	204.6	210.6	216.9	223.3	229.9	236.8	244.0	251.3	258.8
Chelan Co. PUD #1	156.1	162.4	168.1	174.2	180.0	186.5	193.5	200.4	207.2	214.3	221.9	229.1	236.3	243.8	251.4
Clallam Co. PUD #1	67.0	70.9	75.0	79.4	84.0	88.9	94.1	99.6	105.3	111.3	117.5	124.0	130.7	137.9	145.2
Clark Co. PUD #1	430.6	448.3	466.0	484.4	502.7	521.3	540.0	558.9	577.9	595.3	616.2	635.5	655.7	676.2	696.1
Clatskanie PUD	109.0	118.1	128.1	138.9	144.9	145.5	160.2	177.4	187.3	204.5	208.7	213.0	217.3	221.6	222.6
Cowlitz Co. PUD #1	616.6	632.9	653.0	665.4	677.9	690.4	703.9	716.2	729.4	743.5	756.7	770.3	784.0	797.6	810.1
Douglas Co. PUD #1	77.5	81.0	84.6	88.8	93.2	97.7	102.5	107.8	113.7	119.8	126.1	133.1	140.5	148.3	157.0
Franklin Co. PUD #1	102.3	106.7	112.1	117.7	122.9	128.5	134.5	140.9	147.7	154.9	162.5	170.6	179.1	188.2	197.8
Grant Co. PUD #2	231.3	240.9	251.0	263.0	275.3	288.6	303.0	318.1	334.1	350.7	368.3	386.7	406.0	426.3	447.7
Grays Harbor Co. PUD #1	213.4	221.4	229.8	238.5	247.6	257.0	266.7	276.8	287.3	298.2	309.5	321.2	333.4	346.0	359.0
Klickitat Co. PUD #1	33.6	35.6	37.7	40.0	42.3	44.8	47.6	50.5	53.8	56.9	60.3	63.9	67.7	71.5	75.8
Lewis Co. PUD #1	114.5	120.3	126.4	132.8	139.6	146.8	154.3	162.2	170.6	179.3	188.4	197.8	207.6	217.9	228.6
Mason Co. PUD #3	61.1	65.0	69.1	73.5	78.2	83.3	88.6	94.3	100.4	106.6	113.3	120.2	127.5	135.1	143.2
Northern Wasco PUD	29.1	30.1	31.0	31.9	32.8	33.9	34.9	36.0	37.2	38.3	39.5	40.7	42.1	43.4	44.7
Okanogan Co. PUD #1	73.9	77.7	81.9	86.3	90.8	95.6	100.7	106.1	111.6	117.6	123.7	130.0	136.7	143.7	151.0
Pacific Co. PUD #2	43.7	46.0	48.4	50.9	53.6	56.4	59.3	62.4	65.6	69.0	72.4	76.1	79.9	83.9	87.8
Snohomish Co. PUD #1	653.4	667.0	680.2	692.8	705.4	717.6	729.2	740.2	750.8	760.8	770.2	779.0	787.2	795.4	802.4
Tillamook Co. PUD #1	46.6	47.7	48.7	49.7	50.9	52.0	53.1	54.3	55.4	56.6	57.9	59.1	60.4	61.7	63.0
Total Large PUD's	3457.8	3590.9	3730.8	3870.6	4009.0	4147.7	4307.2	4471.0	4630.7	4801.6	4967.8	5138.3	5316.1	5501.2	5688.0
Large Coop's															
Benton REA	55.1	59.4	64.2	69.5	75.2	81.5	88.4	96.0	104.1	112.9	122.4	132.5	143.6	155.4	168.0
Big Bend Electric Coop.	86.9	96.8	107.7	120.1	134.0	149.9	167.5	187.3	209.4	234.1	261.5	292.1	326.1	363.8	405.7
Central Electric Coop.	39.5	42.3	45.3	48.5	52.0	55.7	59.6	63.9	68.4	73.1	78.1	83.3	88.9	94.7	100.8
Consumers Power, Inc.	61.1	65.7	70.8	76.2	81.9	88.3	95.1	102.6	110.5	119.0	128.0	137.7	147.9	158.9	170.5
Coos-Curry Electric Coop.	38.2	40.0	41.9	44.0	46.1	48.3	50.6	53.1	55.7	58.4	61.3	64.4	67.6	71.0	74.6
Inland Power & Light Co.	91.8	100.9	110.7	121.5	133.6	147.2	162.1	178.5	196.9	216.8	238.7	262.5	288.6	317.2	348.4
Lane Co. Electric Coop.	36.1	37.4	38.6	39.9	41.3	42.7	44.1	45.6	47.3	48.9	50.5	52.3	54.1	56.0	57.9
Peninsula Light Co., Inc.	43.1	46.8	50.9	55.1	59.2	63.4	67.4	71.2	75.1	79.0	82.9	86.9	91.2	95.6	100.2
Raft River Electric Coop.	33.1	34.5	35.8	37.2	38.7	40.2	41.7	43.3	45.0	46.8	48.6	50.5	52.4	54.4	56.5
Salem Electric	38.1	39.9	41.8	43.8	45.9	48.1	50.4	52.8	55.3	57.9	60.6	63.5	66.4	69.5	72.6
Umatilla Electric Coop.	121.2	124.7	131.5	141.8	145.4	149.4	153.7	158.0	162.5	167.1	171.9	176.9	182.0	187.2	192.6
Total Large Coop's	644.2	688.4	739.2	797.6	853.3	914.7	980.6	1052.3	1130.2	1214.0	1304.5	1402.6	1508.8	1623.7	1747.8
Total Large Customers	6604.1	6849.5	7108.0	7371.1	7635.1	7900.8	8176.4	8471.1	8774.9	9095.1	9416.7	9749.0	10096.3	10460.2	10833.5

Table III

BPA PREFERENCE CUSTOMER'S ESTIMATED FIRM ENERGY
REQUIREMENTS FOR JULY-JUNE OPERATING YEARS
1983-84 THROUGH 1997-98
AVERAGE MEGAWATTS

Sheet 2 of 4

SMALLER CUSTOMERS	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Small Municipals															
Albion, Idaho	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
Bandon, Oregon	8.1	8.4	8.8	9.0	9.3	9.6	9.9	10.2	10.5	10.9	11.3	11.6	12.0	12.4	12.7
Blaine, Washington	5.4	5.6	5.8	6.1	6.3	6.5	6.8	7.1	7.4	7.6	8.0	8.3	8.6	8.9	9.3
Bonners Ferry, Idaho	7.9	8.2	8.4	8.8	9.1	9.4	9.7	10.1	10.5	10.8	11.2	11.6	12.0	12.5	12.9
Burley, Idaho	16.8	18.4	20.2	22.1	24.3	26.6	29.2	32.0	35.0	38.4	41.9	45.8	50.0	54.5	59.3
Canby, Oregon	16.2	17.6	19.1	20.7	22.5	24.4	26.5	28.7	31.1	33.7	36.4	39.4	42.5	45.9	49.5
Cascade Locks, Oregon	5.1	5.2	5.2	5.4	5.5	5.6	5.7	5.8	5.9	6.0	6.2	6.3	6.5	6.6	6.8
Centralia, Washington	27.4	28.6	29.8	31.1	32.4	33.8	35.3	36.9	38.4	40.1	41.8	43.6	45.4	47.3	49.3
Cheney, Washington	14.9	15.3	15.8	16.2	16.7	17.1	17.6	18.1	18.6	19.1	19.7	20.2	20.8	21.4	22.0
Consolidated ID No. 19, Wash.	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
Coulee Dam, Washington	4.5	4.6	4.8	5.0	5.2	5.3	5.5	5.7	5.9	6.1	6.3	6.5	6.7	7.0	7.2
Declo, Idaho	.7	.7	.7	.7	.7	.7	.7	.7	.7	.7	.7	.7	.7	.7	.7
Drain, Oregon	3.9	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.6	4.7	4.8	4.9	5.1	5.2
Eatonville, Washington	1.7	1.7	1.8	1.9	1.9	2.0	2.1	2.1	2.2	2.3	2.4	2.5	2.6	2.7	2.7
Ellensburg, Washington	24.8	25.6	26.4	27.2	28.1	29.0	29.9	30.8	31.8	32.8	33.8	34.9	36.0	37.2	38.3
Fircrest, Washington	6.5	6.6	6.8	7.0	7.2	7.4	7.6	7.8	8.1	8.3	8.5	8.7	9.0	9.3	9.6
Forest Grove, Oregon	26.2	27.8	29.6	31.5	33.5	35.6	37.8	40.2	42.6	45.2	47.9	50.7	53.7	56.8	60.0
Heyburn, Idaho	12.7	13.3	13.9	14.6	15.3	16.1	16.9	17.7	18.5	19.4	20.3	21.3	22.3	23.3	24.4
McCleary, Washington	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9
Milton, Washington	3.5	3.6	3.7	3.9	4.0	4.2	4.4	4.6	4.7	4.9	5.1	5.3	5.5	5.7	6.0
Milton-Freewater, Oregon	19.5	20.7	22.0	23.4	24.9	26.5	28.2	30.1	32.0	34.1	36.2	38.5	40.9	43.3	46.0
Minidoka, Idaho	.1	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
Monmouth, Oregon	8.0	8.2	8.4	8.7	8.9	9.2	9.5	9.8	10.1	10.4	10.7	11.0	11.4	11.7	12.0
Rupert, Idaho	10.8	11.7	12.7	13.8	15.0	16.4	18.0	19.7	21.7	23.9	26.3	29.0	31.9	35.3	38.8
Steilacoom, Washington	5.8	6.1	6.4	6.8	7.1	7.5	7.9	8.3	8.7	9.2	9.6	10.1	10.6	11.1	11.6
Sumas, Washington	1.2	1.2	1.3	1.4	1.4	1.5	1.6	1.7	1.7	1.8	1.9	1.9	2.0	2.1	2.2
Vera IRA District, Washington	23.0	24.3	25.9	27.9	30.3	33.3	37.1	39.8	42.9	46.4	50.3	54.8	59.7	65.3	71.6
Total Small Municipals	259.9	272.8	287.1	303.0	319.6	337.9	358.3	378.5	399.8	423.0	447.6	474.0	502.3	532.8	564.9
Small PUD's															
Ferry Co. PUD #1	8.7	9.2	9.6	10.1	10.6	11.2	11.8	12.4	13.0	13.7	14.4	15.1	15.9	16.6	17.5
Kittitas Co. PUD-#1	6.5	6.9	7.3	7.5	7.8	8.2	8.6	8.9	9.4	9.8	10.2	10.7	11.1	11.6	12.1
Mason Co. PUD #1	9.1	9.6	10.2	10.8	11.4	12.1	12.8	13.6	14.4	15.2	16.1	17.0	17.9	18.9	19.9
Pend Oreille Co. PUD #1	21.0	22.0	23.1	24.3	25.5	26.8	28.1	29.5	31.0	32.5	34.1	35.8	37.6	39.5	41.5
Skamania Co. PUD #1	18.4	19.2	20.1	21.1	22.2	23.2	24.3	25.5	26.7	28.0	29.3	30.7	32.1	33.6	35.2
Wahkiakum Co. PUD #1	7.3	7.6	8.0	8.3	8.7	9.0	9.4	9.8	10.2	10.6	11.1	11.5	12.0	12.5	13.0
Whatcom Co. PUD #1	14.5	14.5	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6
Total Small PUD's	85.5	89.0	92.9	96.7	100.8	105.1	109.6	114.3	119.3	124.4	129.8	135.4	141.2	147.3	153.8

Table III

EPA PREFERENCE CUSTOMER'S ESTIMATED FIRM ENERGY
REQUIREMENTS FOR JULY-JUNE OPERATING YEARS
1983-84 THROUGH 1997-98
AVERAGE MEGAWATTS

Sheet 3 of 4

SMALLER CUSTOMERS	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Small Coop's (Excl. Montana)															
Alder Mutual	.3	.4	.4	.4	.4	.4	.4	.4	.4	.4	.4	.4	.4	.4	.4
Blachly Lane Elec. Coop.	18.7	19.6	20.5	21.4	22.3	23.3	24.4	25.5	26.8	27.9	29.2	30.6	32.0	33.4	34.9
Clearwater Power Co.	26.8	28.3	29.9	31.5	33.2	35.0	36.8	38.8	40.9	43.1	45.3	47.7	50.2	52.8	55.5
Columbia Basin Elec. Coop.	21.5	22.5	23.6	24.8	26.0	27.3	28.6	30.0	31.6	33.1	34.7	36.4	38.1	40.0	41.9
Columbia Power Coop.	3.8	4.0	4.2	4.4	4.5	4.7	4.9	5.1	5.3	5.5	5.7	6.0	6.2	6.4	6.7
Columbia REA	31.5	33.7	35.7	37.8	40.0	42.3	44.8	47.4	50.2	53.2	56.2	59.4	62.7	66.2	69.9
Douglas Elec. Coop.	23.1	24.6	26.1	27.8	29.6	31.5	33.7	35.9	38.3	41.0	43.7	46.6	49.7	53.1	56.6
East End Mutual	1.9	2.0	2.2	2.4	2.6	2.8	3.0	3.3	3.5	3.8	4.1	4.4	4.8	5.1	5.5
Elmhurst Mutual	25.4	27.2	29.1	31.2	33.5	35.9	38.4	41.2	44.1	47.2	50.4	53.8	57.4	61.2	65.1
Fall River Elec. Coop.	29.9	32.5	35.3	38.5	41.9	45.6	49.7	54.1	58.8	64.0	69.6	75.5	81.9	88.7	96.1
Farmers Elec. Co.	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.1	2.2	2.3	2.5	2.7	2.9	3.0	3.2
Harney Elec. Coop.	20.6	21.6	22.7	23.7	24.9	26.1	27.3	28.6	30.0	31.4	32.9	34.4	36.0	37.6	39.3
Hood River Elec. Coop.	12.7	13.3	13.8	14.4	15.0	15.6	16.2	16.9	17.6	18.3	19.1	19.8	20.6	21.5	22.3
Idaho Co. L.& P. Coop.	7.1	7.5	7.9	8.4	8.9	9.6	10.3	11.0	11.8	12.7	13.6	14.6	15.6	16.7	17.9
Kootenai Elec. Coop., Inc.	26.5	28.4	30.4	32.6	34.9	37.4	40.1	42.9	46.0	49.2	52.6	56.2	60.0	64.0	68.2
Lakeview L.& P. Co.	27.5	28.5	29.6	30.7	31.9	33.1	34.3	35.6	37.0	38.4	39.8	41.3	42.9	44.5	46.1
Lincoln Elec. Coop. (Wash.)	24.2	26.0	27.7	29.6	31.7	33.8	36.2	38.7	41.4	44.2	47.2	50.3	53.7	57.1	60.8
Lost River Elec. Coop.	9.3	9.7	10.2	10.8	11.3	12.0	12.6	13.3	14.0	14.7	15.5	16.3	17.2	18.0	18.9
Lower Valley P. & L. Co.	51.8	57.1	62.9	69.3	76.4	84.2	92.8	102.3	112.5	123.7	135.8	149.1	163.4	178.9	195.7
Midstate Elec. Coop.	23.4	24.9	26.4	28.1	29.9	31.8	33.8	35.9	38.2	40.6	43.0	45.6	48.3	51.1	54.1
Nespelem Valley Elec. Coop.	6.3	6.7	7.1	7.5	7.9	8.4	8.9	9.5	10.2	10.7	11.5	12.2	12.9	13.7	14.6
Northern Lights, Inc. 2/	21.7	22.9	24.3	25.9	27.5	29.3	31.1	33.3	35.5	37.7	40.3	42.9	45.5	48.6	51.7
Ohop Mutual	4.5	4.8	5.1	5.4	5.7	6.1	6.4	6.8	7.2	7.6	8.1	8.5	9.0	9.5	10.0
Okanogan Co. Elec. Coop.	4.2	4.5	4.8	5.0	5.3	5.6	5.9	6.2	6.6	6.9	7.3	7.7	8.1	8.5	9.0
Orcas P. & L. Co.	18.8	20.1	21.4	22.9	24.4	26.0	27.7	29.5	31.3	33.3	35.3	37.4	39.6	41.9	44.4
Parkland L. & W. Co.	12.8	13.1	13.5	13.9	14.3	14.7	15.1	15.5	16.0	16.4	16.9	17.4	17.9	18.4	18.9
Prairie Power Coop.	2.6	2.8	3.0	3.3	3.6	3.9	4.2	4.5	4.9	5.3	5.7	6.2	6.7	7.2	7.7
Riverside Elec. Co.	1.4	1.5	1.6	1.8	1.9	2.1	2.2	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.7
Rural Elec. Co.	10.0	10.5	11.1	11.6	12.1	12.6	13.1	13.6	14.3	14.9	15.5	16.2	16.8	17.6	18.4
Salmon River Elec. Coop.	6.1	6.5	6.8	7.2	7.7	8.1	8.6	9.1	9.7	10.2	10.8	11.4	12.1	12.7	13.4
South Side Elec. Lines	3.9	4.1	4.3	4.4	4.6	4.7	4.9	5.0	5.2	5.4	5.6	5.8	6.0	6.2	6.4
Surprise Valley Elec. Corp.	16.4	17.5	18.6	19.8	21.1	22.5	23.9	25.5	27.2	29.0	30.8	32.7	34.8	37.0	39.2
Tanner Electric	4.1	4.5	4.9	5.4	6.0	6.6	7.2	8.0	8.7	9.6	10.6	11.6	12.7	14.0	15.3
Unity L. & P. Co.	7.6	8.1	8.7	9.3	9.9	10.6	11.3	12.1	12.9	13.8	14.7	15.6	16.6	17.7	18.8
Wasco Elec. Coop.	13.5	14.3	15.0	15.7	16.4	17.2	18.1	18.9	19.9	20.9	21.9	23.0	24.1	25.3	26.6
Wells Rural Elec. Co.	13.6	15.2	17.0	19.1	21.4	24.1	26.9	30.2	33.7	37.7	42.0	46.9	52.2	58.1	64.6
West Oregon Elec. Coop.	11.1	11.6	12.3	12.9	13.5	14.1	14.7	15.4	16.1	16.9	17.6	18.4	19.3	20.2	21.2
Total Small Coop's (Excl. Mont.)	545.9	581.9	619.6	660.5	703.9	750.8	800.4	854.4	912.5	973.7	1038.8	1108.1	1181.6	1259.8	1343.0
Total Small Pref. Customers (Excl. Montana)	891.3	943.7	999.6	1060.2	1124.3	1193.8	1268.3	1347.2	1431.6	1521.1	1616.2	1717.5	1825.1	1939.9	2061.7

Table III

BPA PREFERENCE CUSTOMER'S ESTIMATED FIRM ENERGY
REQUIREMENTS FOR JULY-JUNE OPERATING YEARS
1983-84 THROUGH 1997-98
AVERAGE MEGAWATTS

Sheet 4 of 4

SMALLER CUSTOMERS	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Small Coop's (Montana Only)															
Flathead Elec. Coop.	18.5	19.8	21.1	22.6	24.1	25.8	27.5	29.4	31.4	33.5	35.7	38.0	40.4	42.9	45.6
Glacier Elec. Coop.	20.6	21.1	21.6	22.1	22.6	23.2	23.7	24.2	24.8	25.4	26.0	26.6	27.2	27.8	26.5
Lincoln Elec. Coop. (Montana)	7.8	8.1	8.3	8.6	8.9	9.1	9.4	9.6	9.9	10.2	10.5	10.8	11.1	11.4	11.8
Missoula Elec. Coop.	18.5	19.8	21.3	22.9	24.6	26.4	28.4	30.6	32.8	35.4	37.8	40.7	43.6	46.8	50.0
Northern Lights, Inc. 3/	12.9	13.3	13.6	13.8	14.1	14.4	14.8	15.0	15.4	15.8	16.1	16.5	17.0	17.4	17.9
Ravalli Elec. Coop.	13.3	14.0	14.9	15.7	16.7	17.6	18.7	19.7	20.8	22.1	23.2	24.5	25.9	27.3	28.7
Vigilante Elec. Coop.	12.9	13.9	15.1	16.3	17.6	18.8	20.0	21.3	22.8	24.4	26.1	27.8	29.5	31.5	33.6
Total Small Coop's (Montana)	104.5	110.0	115.9	122.0	128.6	135.3	142.5	149.8	157.9	166.8	175.4	184.9	194.7	205.1	216.1
Total Small Coop's	650.4	691.9	735.5	782.5	832.5	886.1	942.9	1004.2	1070.4	1140.5	1214.2	1293.0	1376.3	1464.9	1559.1
Total Small Pref. Customers	995.8	1053.7	1115.5	1182.2	1252.9	1329.1	1410.8	1497.0	1589.5	1687.9	1791.6	1902.4	2019.8	2145.0	2277.8
Total Large Pref. Customers 4/	6604.1	6849.5	7108.0	7371.1	7635.1	7900.8	8176.4	8471.1	8774.9	9095.1	9416.7	9749.0	10096.3	10460.2	10833.5
Total Small Pref. Customers 5/ Excl. Montana Coop's	891.3	943.7	999.6	1060.2	1124.3	1193.8	1268.3	1347.2	1431.6	1521.1	1616.2	1717.5	1825.1	1939.9	2061.7
Montana Coop's Only	104.5	110.0	115.9	122.0	128.6	135.3	142.5	149.8	157.9	166.8	175.4	184.9	194.7	205.1	216.1
Total Small Pref. Cust.	995.8	1053.7	1115.5	1182.2	1252.9	1329.1	1410.8	1497.0	1589.5	1687.9	1791.6	1902.4	2019.8	2145.0	2277.8
Total Preference Customers Excl. Montana Coop's	7495.4	7793.2	8107.6	8431.3	8759.4	9094.6	9444.7	9818.3	10206.5	10616.2	11032.9	11466.5	11921.4	12400.1	12895.2
Incl. Montana Coop's	7599.9	7903.2	8223.5	8553.3	8888.0	9229.9	9587.2	9968.1	10364.4	10783.0	11208.3	11651.4	12116.1	12605.2	13111.3

1/ From PNUCC April 23, 1979, "Long-Range Projection of Loads & Resources," 1979-80 Through 1998-99.

2/ Loads excluding the State of Montana.

3/ Loads in State of Montana only.

4/ Loads exceed the minimum allocation.

5/ Loads are less than the minimum allocation.

Table IV

Existing BPA Preference Customers[1]
Estimated System Loads, Calculated BPA Allocations, BPA Obligations, and Utility Deficits
By Year of Contract Expiration
(Average Megawatts)[2]

Col 1 Contract Expiration Year	Col 2 Contract Expir. Date	Col 3 Sys Load Fall '78 Estimate	Col 4 Net Resources 1975-76	Col 5 Net Sys Req'nts Fall '78 Estimate	Col 6[3] Hydro Alloc	Col 7 Thermal Alloc	Col 8 CSPE Purch Incl BPA Guarantee	Col 9[4] Calc BPA Alloc Incl CSPE (Columns 6+7+8)	Col 10 BPA Obligation Incl CSPE Guarantee Total Obl	Col 11 BPA Obligation Incl CSPE Guarantee Prorated Obl	Col 12 Deficit (Col 9-Col 5)
1983-84											
Farmers Elec. Coop.	08/07/83	1.3		1.3	25.0	0.2		25.2	1.3	0.1	—
East End Mutual	08/21/83	1.9		1.9	25.0	0.5		25.5	1.9	0.3	—
Lost River Elec. Coop.	08/21/83	9.3		9.3	25.0	0.5		25.5	9.3	1.6	—
Burley, Idaho	08/30/83	16.8		16.8	25.0	3.0		28.8	16.8	2.8	—
Riverside Elec. Co.	08/30/83	1.4		1.4	25.0	0.2		25.2	1.4	0.2	—
Salmon River Electric Coop.	08/30/83	6.1		6.1	25.0	0.8		25.8	6.1	1.0	—
Albion, Idaho	08/31/83	0.5		0.5	25.0	0.2		25.2	0.5	0.1	—
Declo, Idaho	08/31/83	0.7		0.7	25.0	0.3		25.3	0.7	0.1	—
Heyburn, Idaho	08/31/83	12.7		12.7	25.0	3.9		28.9	12.7	2.1	—
Minidoka, Idaho	08/31/83	0.1		0.1	25.0	—		25.0	0.1	—	—
Surprise Valley Elec. Corp.	09/30/83	16.4		16.4	25.0	3.6		28.6	16.4	4.1	—
1984-85											
Clatskanie PUD	09/01/84	118.1		118.1	62.5	31.8	1.0	95.3	95.3	15.9	-22.8
Bandon, Oregon	12/31/84	8.4		8.4	25.0	1.5		26.5	8.4	4.2	—
Eatonville, Washington		1.7		1.7	15.0*	0.4		15.4	1.7	0.9	—
Ellensburg, Washington		25.6		25.6	25.0	6.4		31.4	25.6	12.8	—
Eugene, Oregon		311.0	46.3	264.7	184.1	51.5	26.8	262.4	262.4	131.2	-2.3
Fircrest, Washington		6.6		6.6	15.5*	1.1		16.6	6.6	3.3	—
Forest Grove, Oregon		27.8		27.8	25.0	7.7	1.5	34.2	27.8	13.9	—
Milton, Washington		3.6		3.6	15.2*	0.8		16.0	3.6	1.8	—
Monmouth, Oregon		8.2		8.2	25.0	1.0		26.0	8.2	4.1	—
Port Angeles, Washington		108.3		108.3	60.9	28.6	2.4	91.9	91.9	46.0	-16.4
Steilacoom, Washington		6.1		6.1	25.0	1.5		26.5	6.1	3.1	—
Central Lincoln PUD		177.4		177.4	118.0	41.6	4.9	164.5	164.5	82.3	-12.9
Mason Co. PUD #1		9.6		9.6	25.0	1.8		26.8	9.6	4.8	—
Pend Oreille Co. PUD #1		22.0	13.4	8.6	25.0	5.3	1.0	31.3	8.6	4.3	—
Wahkiakum Co. PUD #1		7.6		7.6	25.0	1.6		26.6	7.6	3.8	—
Alder Mutual		0.4		0.4	25.0	0.1		25.1	0.4	0.2	—
Central Elec. Coop.		42.3		42.3	25.0	11.6		36.6	36.6	18.3	-5.7
Elmhurst Mutual		27.2		27.2	25.0	8.0		33.0	27.2	13.6	—
Flathead Elec. Coop.		19.8		19.8	25.0	3.9	0.5	29.4	19.8	9.9	—
Glacier Elec. Coop.		21.1		21.1	25.0	6.6		31.6	21.1	10.6	—
Lakeview L & P Co.		28.5		28.5	18.8*	5.5		24.3	24.3	12.2	-4.2
Lincoln Elec. Coop. (Mont.)		8.1		8.1	25.0	1.7	0.5	27.2	8.1	4.1	—
Missoula Elec. Coop.		19.8		19.8	25.0	7.0	0.5	32.5	19.8	9.9	—
Northern Lights, Inc.		36.2		36.2	25.0	15.1	1.7	41.8	36.2	18.1	—
Ohop Mutual		4.8		4.8	25.0	0.8		25.8	4.8	2.4	—
Parkland L & W		13.1		13.1	25.0	1.3		26.3	13.1	6.6	—
Peninsula Light Co.		46.8		46.8	25.0	12.1		37.1	37.1	18.6	-9.7
Ravalli Elec. Coop		14.0		14.0	25.0	4.9	0.5	30.4	14.0	7.0	—
West Oregon Elec. Coop.	12/31/84	11.6		11.6	25.0	2.4		27.4	11.6	5.8	—
Raft River Elec. Coop.	06/15/85	34.5		34.5	25.0	1.5		26.5	26.5	26.5	-8.0
1985-86											
McCleary, Washington	11/30/85	4.7		4.7	25.0	0.6		25.6	4.7	2.0	—
Clallam Co. PUD #1	12/31/85	75.0		75.0	40.6	19.0		59.6	59.6	29.8	-15.4
Whatcom Co. PUD #1	12/31/85	14.6		14.6	25.0	0.8		25.8	14.6	7.3	—
Cowlitz Co. PUD #1	01/31/86	653.0	9.1	643.9	308.7	224.6	12.2	545.5	545.5	318.2	-98.4
Tillamook PUD	02/23/86	48.7		48.7	37.3	7.0	2.4	46.7	46.7	31.1	-2.0
Douglas Elec. Coop.	03/21/86	26.1		26.1	25.0	6.2		31.2	26.1	19.6	—
Consolidated ID No. 19	04/20/86	0.2		0.2	25.0	—		25.0	0.2	0.2	—
Nespelem Valley Elec. Coop.	05/04/86	7.1		7.1	25.0	0.5	0.2	25.7	7.1	5.9	—
Okanogan Co. PUD #1	05/20/86	81.9		81.9	44.4	21.6		66.0	66.0	60.5	-15.9
Milton-Freewater, Oregon	06/30/86	22.0		22.0	25.0	4.5		29.5	22.0	22.0	—
1986-87											
Blaine, Washington	07/21/86	6.1		6.1	25.0	1.2		26.2	6.1	0.5	—
Tanner Electric	09/26/86	5.4		5.4	25.0	1.5		26.5	5.4	1.4	—
Salem Electric	10/04/86	43.8		43.8	25.0	11.5	2.0	38.5	38.5	9.6	-5.3
Springfield, Oregon	12/06/86	131.9		131.9	72.9	33.8	2.4	109.1	109.1	45.5	-22.8
Harney Elec. Coop.	12/21/86	23.7		23.7	25.0	3.0		28.0	23.7	11.9	—
Lewis Co. PUD #1	03/06/87	132.8	0.1	132.7	62.8	38.6		101.4	101.4	67.6	-31.3
Hood River Elec. Coop.	03/31/87	14.4		14.4	25.0	3.1		28.1	14.4	10.8	—
Centralia, Washington	04/22/87	31.1	10.1	21.0	25.0	6.3		31.3	21.0	17.5	—
Rupert, Idaho	05/05/87	13.8		13.8	25.0	3.1		28.1	13.8	11.5	—
Benton REA	06/01/87	69.5		69.5	25.0	3.9		28.9	28.9	26.5	-40.6
Blachly-Lane Elec. Coop.	06/07/87	21.4		21.4	25.0	5.4		30.4	21.4	19.6	—

1/ There are only 115 preference customers shown. Washington Public Power Supply System (WPPSS) is not included. WPPSS is a preference customer eligible to receive firm energy while constructing thermal power plants.

2/ Average megawatts are determined by dividing megawatthours by the number of hours in a specific period (in this case, an operating year).

3/ Some former utility customers of Tacoma City Light receive hydro allocations of less than 25 average MW through contractual agreements, to which BPA, Tacoma, and the affected utilities are parties.

4/ Amounts shown will be reduced by 15 percent to reflect establishment of a conservation reserve.

DRAFT

Bonneville Power Administration
September 13, 1979

Table IV

Existing BPA Preference Customers 1/
Estimated System Loads, Calculated BPA Allocations, BPA Obligations, and Utility Deficits
By Year of Contract Expiration
(Average Megawatts) 2/

Col 1 Contract Expiration Year	Col 2 Contract Expir. Date	Col 3 Sys Load Fall '78 Estimate	Col 4 Net Resources 1975-76	Col 5 Net Sys Req'mts Fall '78 Estimate	Col 6 3/ Hydro Alloc	Col 7 Thermal Alloc	Col 8 CSPE Purch Incl BPA Guarantee	Col 9 4/ Calc BPA Alloc Incl CSPE (Columns 6+7+8)	Col 10 BPA Obligation Incl CSPE Guarantee Total Obl	Col 11 Prorated Obl	Col 12 Deficit (Col 9-Col 5)
1987-88											
Inland P & L Co.	07/26/87	133.6		133.6	40.6	32.5	2.4	75.5	75.5	6.3	-58.1
Coulee Dam, Washington	08/30/87	5.2		5.2	25.0	1.3	0.5	26.8	5.2	0.9	—
Vigilante Elec. Coop.	09/08/87	17.6		17.6	25.0	3.8		28.8	17.6	2.9	—
Columbia REA	10/09/87	40.0		40.0	25.0	10.7		35.7	35.7	8.9	-4.3
Vera Irrig. Dist.	10/27/87	30.3		30.3	25.0	6.1	1.0	32.1	30.3	10.1	—
Prairie Power Coop.	11/07/87	3.6		3.6	25.0	1.4		26.4	3.6	1.2	—
Kittitas Co. PUD #1	11/29/87	7.8	0.9	6.9	25.0	1.7		26.7	6.9	2.9	—
Unity L & P Co.	01/08/88	9.9		9.9	25.0	2.2		27.2	9.9	5.0	—
Skamania Co. PUD #1	03/21/88	22.2		22.2	25.0	3.7	1.0	29.7	22.2	16.6	—
Clearwater Power Co.	03/21/88	33.2		33.2	25.0	5.0		30.0	30.0	22.5	-3.2
Drain, Oregon	05/23/88	4.2		4.2	25.0	0.7		25.7	4.2	3.9	—
Kootenai Elec. Coop.	06/03/88	34.9		34.9	25.0	8.1		33.1	33.1	30.3	-1.8
1988-89											
Big Bend Elec. Coop	07/09/88	149.9		149.9	35.5	6.4		41.9	41.9	—	-108.0
Orcas P & L Co.	07/31/88	26.0		26.0	25.0	6.2		31.2	26.0	2.2	—
Idaho Co. L & P Co.	08/27/88	9.6		9.6	25.0	0.7	0.5	26.2	9.6	1.6	—
Grant Co. PUD #2	08/31/88	288.6	31.5	257.1	93.0	52.5	2.2	147.7	147.7	24.6	-109.4
Fall River Elec. Coop.	08/31/88	45.6		45.6	25.0	7.2		32.2	32.2	5.4	-13.4
McMinnville, Oregon	10/18/88	48.8		48.8	29.8	9.0	2.0	40.8	40.8	13.6	-8.0
Lane Co. Elec. Coop.	11/16/88	42.7		42.7	31.9	2.6	2.0	36.5	36.5	15.2	-6.2
Lower Valley P & L Co.	12/13/88	84.2	0.9	83.3	25.0	12.1		37.1	37.1	15.5	-46.2
Sumas, Washington	12/17/88	1.5		1.5	25.0	0.3		25.3	1.5	0.8	—
1989-90											
Columbia Basin Elec. Coop.	07/08/89	28.6		28.6	25.0	5.7		30.7	28.6	—	—
Wasco Elec. Coop.	01/29/90	18.1		18.1	25.0	3.1		28.1	18.1	10.6	—
Rural Elec. Coop.	04/10/90	13.1		13.1	25.0	2.5		27.5	13.1	9.8	—
1990-91											
Columbia Power Coop.	07/24/90	5.1		5.1	25.0			25.0	5.1	0.4	—
Clark Co. PUD #1	12/31/90	558.9		558.9	252.7	134.3	14.6	401.6	401.6	200.8	-157.3
Canby, Oregon	03/02/91	28.7		28.7	25.0	6.0		31.0	28.7	19.1	—
Ferry Co. PUD #1	03/21/91	12.4		12.4	25.0	0.4		25.4	12.4	9.3	—
Benton Co. PUD #1	04/01/91	358.3		358.3	108.1	87.9	3.9	199.9	199.9	149.9	-158.4
Consumers Power, Inc.	04/13/91	102.6		102.6	29.3	20.1		49.4	49.4	37.0	-53.2
Cheney, Washington	04/29/91	18.1		18.1	25.0	3.3		28.3	18.1	15.1	—
Umatilla Elec. Coop.	05/06/91	158.0		158.0	57.4	50.1		107.5	107.5	89.6	-50.5
Northern Wasco PUD	06/11/91	36.0		36.0	25.0	6.4		31.4	31.4	28.8	-4.6
Okanogan Co. Elec. Coop.	06/11/91	6.2		6.2	25.0	1.3		26.3	6.2	5.7	—
Franklin Co. PUD # 1	06/25/91	140.9		140.9	51.3	27.4	3.9	82.6	82.6	82.6	-58.3
1991-92											
Midstate Elec. Coop.	10/08/91	38.2		38.2	25.0	8.0		33.0	33.0	8.3	-5.2
Pacific Co. PUD #2	11/05/91	65.6		65.6	27.2	12.0		39.2	39.2	13.1	-26.4
1992-93											
Wells Rural Elec. Co.	07/27/92	37.7		37.7	25.0	0.4		25.4	25.4	2.1	-12.3
Snohomish Co. PUD #1	08/10/92	760.8	0.5	760.3	445.5	162.7	7.3	615.5	615.5	51.3	-144.8
Cascade Locks, Oregon	10/20/92	6.0		6.0	25.0	0		25.0	6.0	2.0	—
Mason Co. PUD #3	12/01/92	106.6	0.1	106.5	36.9	17.1		54.0	54.0	22.5	-52.5
Klickitat Co. PUD #1	03/09/93	56.9		56.9	25.0	7.3		32.3	32.3	21.5	-24.6
Idaho Falls, Idaho	03/31/93	111.0	2.4	108.6	36.7	12.1		48.8	48.8	36.6	-59.8
Grays Harbor Co. PUD #1	03/31/93	298.2		298.2	124.0	54.9	7.3	186.2	186.2	139.6	-112.0
1993-94											
Southside Elec. Lines	07/23/93	5.6		5.6	25.0	0.9		25.9	5.6	0.5	—
Bonners Ferry, Idaho	09/30/93	11.2	1.8	9.4	25.0	1.8	0.2	27.0	9.4	2.4	—
Tacoma, Washington	11/01/93	880.9	258.6	622.3	191.7	157.7	61.0	410.4	410.4	136.8	-211.9
Seattle, Washington	11/04/93	1307.2	709.1	598.1	149.4	174.0	61.0	384.4	384.4	128.1	-213.7
Lincoln Elec. Coop. (Wash.)	12/31/93	47.2		47.2	25.0	4.0	0.5	29.5	29.5	14.8	-17.7
Richland, Washington	01/30/94	98.5		98.5	49.8	22.8	3.9	76.5	76.5	44.6	-22.0
1994-95											
Coos-Curry Elec. Coop.	07/24/94	64.4		64.4	28.7	6.6	2.4	37.7	37.7	3.1	-26.7
Douglas Co. PUD #1	08/31/94	133.1	0.7	132.4	56.0	14.7	1.0	71.7	71.7	12.0	-60.7
Chelan Co. PUD #1	09/20/94	229.1	60.0	169.1	38.1	26.9	4.9	69.9	69.9	17.5	-99.2

1/ There are only 115 preference customers shown. Washington Public Power Supply System (WPPSS) is not included. WPPSS is a preference customer eligible to receive firm energy while constructing thermal power plants.

2/ Average megawatts are determined by dividing megawatthours by the number of hours in a specific period (in this case, an operating year).

3/ Some former utility customers of Tacoma City Light receive hydro allocations of less than 25 average MW through contractual agreements, to which BPA, Tacoma, and the affected utilities are parties.

4/ Amounts shown will be reduced by 15 percent to reflect establishment of a conservation reserve.

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Notes for Table IV
by column heading

Existing BPA Preference Customers

Column 1 Preference customers whose firm power sales contracts expire during the operating year (July 1 - June 30) shown. Some customers have more than one firm power sales contract with BPA. For analytical purposes, BPA assumed that all their contracts would expire on the termination date of the longest running contract.

Column 2 The contract expiration date is the termination date of the longest running power sales contract for each customer.

Column 3 Estimated total system loads of each customer shown for the operating year in which the longest running power sales contract terminates. These load estimates are contained in the PNUCC Report, Long-Range Projection of Power Loads and Resources for Resource Planning, dated April 23, 1979 (Blue Book).

Column 4 Contract year 1975-76 assured resources defined in Section 22 of the General Contract Provisions attached to the Power Sales Contracts of preference customers. These resources are used to determine the hydro allocation under existing agreements.

Column 5 Net customer requirements. (Column 3 minus Column 4).

Columns 6, 7, 8 Hydro allocation, thermal allocation, and Canadian Storage Power Exchange (CSPE) purchases defined in Section 22 of the General Contract Provisions attached to the Power Sales Contracts of preference customers.

Column 9 Sum of Columns 6, 7, and 8. This would be the total Hydro-Thermal-CSPE average megawatt allocation from BPA to each utility under current contracts for the entire contract year within which the contract expires.

Column 10 BPA's estimated obligation to each customer during the contract year in which the power sales contract expires but limited to forecasted requirements.

Note: The obligation shown in Column 10 is less than the calculated contract allocation (Column 9) if the hydro plus thermal plus CSPE allocations exceed the estimated net requirements in Column 5 (Column 5 or Column 9, whichever is smaller).

Column 11 Column 10 prorated by whole months for the contract year within which the power sales contract expires. This is BPA's estimated obligation during the partial year in which the contract expires limited to forecasted requirements.

Column 12 Net preference customer energy deficit based on contract year 1975-76 assured resources after utilizing total BPA allocation. (Column 9 minus Column 5).

Federal Agency Customers of BPA
Within or Adjacent to BPA Preference Customers' Service Territory

Contract Federal Agency Customer	Preference Customer	Average MW1/ Calendar Year (CY) 1978 2/	Percent of BPA Total Federal Agency Customer Load	Expiration Date
Air Force, Fairchild	Inland Power & Light	2.8	3.2	6/85
Bureau of Reclamation, Roza	Benton REA	3.3	3.7	8/88
DOE-Richland-300 Area	Richland, Washington	10.3	11.7	12/84
-FFTF3/ & Midway 230	Benton PUD	30.6	34.7	12/84
Navy-Jim Creek	Snohomish Co. PUD	1.2	1.3	6/93
Bureau of Indian Affairs-Wapato	Benton REA	1.4	1.6	7/85
-Flathead	Missoula Electric Coop.	10.9	12.3	6/90
TOTAL		60.5	68.5	

Not Within or Adjacent to BPA Preference Customer Service Territory

Contract Federal Agency Customer	Local Utility	Average MW1/ Calendar Year (CY) 1978	Percent of BPA Total Federal Agency Customer Load	Expiration Date
Bureau of Mines, Albany	Pacific Power & Light	.8	.9	12/85
Navy-Bangor	Puget Sound Power & Light	12.1	13.7	1/84
-Bremerton	Puget Sound Power & Light	14.9	16.9	7/90
TOTAL		27.8	31.5	
BPA TOTAL FEDERAL AGENCY SERVICE		88.3	100.0	

1/ Average megawatts are determined by dividing megawatthours by the number of hours in a specific period (in this case, a calendar year).

2/ Data available by calendar year only

3/ Reflects partial development of Fast Flux Test Facility (FFTF) Full load development is not expected until 1982.

Bonneville Power Administration
September 21, 1979

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Direct Service Industrial (DSI) Customers of BPA
Within or Adjacent to BPA Preference Customers' Service Territory

DSI Customer 1/	Preference Customer	Average MW 2/ Calendar Year (CY) 1978 3/	Percent of BPA Total DSI Load	Contract Expiration Date
Alcoa-Vancouver	Clark Co. PUD #1	228.1	7.2	6/87
Alcoa-Wenatchee	Chelan Co. PUD #1	215.7	6.8	6/87
Anaconda-Columbia Falls	Flathead Electric Coop.	329.7	10.4	9/87
Intalco-Ferndale	Whatcom Co. PUD #1	421.8	13.3	10/84
Kaiser-Spokane	Inland Power & Light	434.9	13.7	10/86
Kaiser-Tacoma	Tacoma, Washington	149.9	4.7	10/86
Kaiser-Trentwood	Inland Power & Light	53.4	1.7	10/86
Martin-Marietta-The Dalles	Northern Wasco PUD	166.5	5.3	2/88
Martin-Marietta-Goldendale	Klickitat Co. PUD #1	205.7	6.5	2/88
Reynolds-Longview	Cowlitz Co. PUD #1	406.5	12.8	12/86
Carborundum-Vancouver	Clark Co. PUD #1	26.6	.8	12/85
Georgia Pacific-Bellingham	Whatcom Co. PUD #1	7.2	.2	7/84
Oremet-Albany	Consumers Power, Inc.	4.3	.2	5/88
Stauffer-Silver Bow	Vigilante Electric Coop.	50.2	1.6	4/88
TOTAL		2700.5	85.2	

Not Within or Adjacent to BPA Preference Customer Service Territory

DSI Customer	Local Utility	Average MW 2/ Calendar Year (CY) 1978	Percent of BPA Total DSI Load	Contract Expiration Date
Crown Zellerbach-Port Townsend	Puget Sound Power & Light	8.4	.3	8/83
Hanna Nickel-Riddle	Pacific Power & Light	88.2	2.8	6/90
Pacific Carbide	Portland General Elec.	7.2	.2	9/91
Pennwalt	Portland General Elec.	41.1	1.3	12/85
Reynolds-Troutdale	Portland General Elec.	264.0	8.3	12/86
Union Carbide	Portland General Elec.	15.5	.5	5/81
Alcoa-Addy	Washington Water Power	45.9	1.4	6/87
TOTAL		470.3	14.8	
BPA TOTAL DSI SERVICE		3170.8	100.0	

1/ Alumax excluded. BPA contractually committed to provide power. Plant yet to be constructed. If constructed, it would presumably be in Umatilla Electric Cooperative Service territory.

2/ Average megawatts are determined by dividing megawatthours by the number of hours in a specific period (in this case, a calendar year).

3/ Data available by calendar year only.

Bonneville Power Administration
September 21, 1979

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COMPARISON OF PROPOSED AND ALTERNATIVE ALLOCATION POLICIES

ALLOCATION ISSUES	CONTINUATION OF EXISTING POLICIES AND PRACTICES	PROPOSED AND ALTERNATIVE ALLOCATION POLICIES					
		Alternative #1	Alternative #2	Alternative #3 (Proposal)	Alternative #4	Alternative #5	Alternative #6
1. Customers Served							
A. Presently served preference customers	Entitled to preference and priority	same[1]	same	same	same	same	same
B. New qualified preference applicants	No power available until contracts expire and/or new resources become available	Not served	500 MW load assumed	3,000 MW load assumed	Not served	1,500 MW load assumed	1,500 MW load assumed
C. Presently served Federal Agencies	BPA will serve total load	Served by local utility; energy associated with 35 MW peak load served by preference customers eligible for allocation	Total load served by BPA	Served by local utility; the entire load served by preference customers eligible for allocation	Served by local utility; energy associated with 35 MW peak load served by preference customers eligible for allocation	same	same
D. Direct-service industries (DSIs, industries served directly by BPA)	BPA will continue to serve to extent energy available beyond needs of preference customers	Served by local utility; total DSI load served by preference customers eligible for allocation but subject to withdrawal	Served by local utility; total DSI load served by preference customers eligible for allocation	Served by local utility; base 2 quartiles of DSI load served by preference customers eligible for allocation	Served by local utility; energy associated with 35 MW peak load served by preference customers eligible for allocation	Served by local utility; total DSI load served by preference customers eligible for allocation	Served by local utility; total DSI load served by preference customers eligible for allocation but subject to withdrawal
2. Customer-Owned Resources	Resources are used as scheduled in the PNUCC "Blue Book" April 23, 1979	1975-76 assured resources as used in present contract for hydro allocation	X[2]	See footnote 3	All assured resources committed to serve load before BPA allocation	All hydro resources constructed prior to 75-76 must be committed to serve load before BPA allocation	X
3. End-Use Loads Served	No distinction made	same	same	No new or expanding single load which equals or exceeds 10 average MW in any year or in a 3-year period is eligible for allocation	Priority for rural and domestic; withdrawable from all other loads	same	same
4. Amount of Firm Energy Available for Sale							
A. Hydro Plants	Based on critical water flow	same	same	same	same	same	same
B. Thermal Plants	60 percent plant factor first year of operation; 75 percent thereafter	60 percent plant factor first year of operation; 70 percent thereafter	X	X	X	X	X
C. Reserves	Maintain a capacity reserve as part of the firm energy sale equal to 25 percent of DSI total load.	System reserves sold as separate class of power to preference customers	X	X	X	X	X
5. Durations and Terms of Allocation	All existing contracts run to expiration; contracts with presently served customers would be renewed.	As contracts expire, new agreements written so that all contracts expire on 9/20/94	X	New 20-year contracts offered; all contracts will terminate on July 1, 2001; provide 2 years advance notice of each preference customer's allocation on July 1 (e.g., on July 1, 1983, for OY 1985)	New 20-year contracts offered effective July 1, 1983, or when executed; all contracts will expire June 30, 2003	X	X
6. Minimum Allocation	25 average MW minimum continued to presently served preference customers' whose contracts are extended	25 average MW thru September 20, 1994, none thereafter for presently served preference customers only	X	25 average MW thru June 30, 1991, none thereafter for presently served preference customers only	25 average MW thru September 20, 1994, none thereafter for presently served preference customers only	No minimum allocation	X
7. Grades of Power	Firm energy allocated	Firm energy and system reserves allocated	X	X	X	X	X
8. Load Determination and Resource Availability	Preference customers estimates reviewed and approved by BPA	same	same	same	same	same	same
9. Rates	Separate Policy Matter	same	same	same	same	same	same
10. Conservation	Separate Policy Matter	Customer must immediately design a conservation program to achieve a 15 percent savings of what its energy requirements would otherwise have been absent a program in OY 1989-90 or sooner, or an effective conservation program which can be implemented by the utility. If the program is not satisfactory, customer is not eligible for additional allocation. If savings of more than 15 percent, allocation may be increased by 1 percent for each 1 percent over 15 percent in the operating year in which excess savings are realized.	X	X	X	X	X

1/-A "same" indicates no departure from the "Continuation of Existing Policies and Practices" Alternative.
2/-An "X" indicates no departure from the previous alternative.
3/-As of July 1, 1983, all generating resources owned or purchased (including those withdrawn or withdrawable) which are equal to or less costly than BPA firm energy are to be used in customer's own system. Such resources will affect the customer's base allocation, if any. All other resources will be made available at cost first to BPA, second to BPA's preference customers, and third to other regional entities. If their resources are disposed of in a different manner, the amount of the BPA allocation will be reduced by the amount of the resource sold.

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Bonneville Power Administration
September 21, 1979

BILLING CODE 6450-01-C

Exhibit

Section 22—General Contract Provisions Attached to Existing Power Sales Contracts

"(i) the larger of (A) 25,000 average kilowatts of energy (219 million kilowatt-hours), or (B) the amount, for the Contract Year commencing July 1, 1975 (Contract Year 1976), of the Purchaser's system firm energy load, less the assured energy capability of the Purchaser's resources, excluding from such assured energy capability the energy supplied by the Administrator to the Purchaser's system under the Hanford Exchange Agreement and the Canadian Entitlement Exchange Agreement; *provided however*, that if the Purchaser has available to it a hydroelectric resource which operated to supply a portion of its system loads in the Contract year commencing July 1, 1974, the Purchaser's allocation for each Contract Year commencing on or after July 1, 1983, shall be reduced by the amount, if any, by which the assured energy capability, as determined by the Administrator, for such resource in such Contract Year exceeds the assured energy capability, as determined by the Administrator, for such resource in Contract Year 1976;

"(ii) an amount of Firm Energy determined by multiplying 1881.8 average megawatts, the amount of Firm Energy determined to be available to the Administrator for each Contract Year from the Trojan Project and from Washington Public Power Supply System's Nuclear Projects Nos. 1, 2 and 3 ("Thermal Plants"), by a fraction whose numerator is the difference between the Purchaser's system firm energy load for the Contract Year prior to the effective date of the notice of insufficiency, and for the Contract Year 1976, and whose denominator is the sum of the differences in system firm energy loads for such Contract Years for all of the Administrator's Northwest preference customers having power sales contracts with the Administrator which contain a provision similar to this provision; *provided however*, that the determination of the Purchaser's system firm energy load for the Contract Year prior to the effective date of the notice of insufficiency used in the above computation shall not exceed 103 percent of the Purchaser's estimated system firm energy load for such Contract Year specified in the Purchaser's estimate furnished the Administrator as of December 31, 1973; *provided further*, that for applicable contract years the 1881.8 average megawatts specified above shall be either increased by the amount the Administrator determines is available to the Administrator through addition Net Billing Agreements from other thermal projects, including Centralia and Boardman (Pebble Springs), or decreased by the amount the Administrator determines is withdrawn from Trojan; and

"(iii) an amount of Firm Energy determined by subtracting the Purchaser's Canadian Entitlement energy, prior to any exchange made pursuant to section 5(c) of the Canadian Entitlement Exchange Agreement, for such Contract Year beginning one year after the notice of insufficiency becomes effective, from the Purchaser's entitlement for Canadian Entitlement energy, prior to any exchange pursuant to section 5(c) of the Canadian Entitlement Exchange Agreement, in the Contract Year which begins the date the notice of insufficiency becomes effective.

"The Purchaser's allocation, determined pursuant to subsection (a)(1), shall not be affected by the Purchaser's acquisition or reconstruction of electric power resources after June 30, 1976.

"(2) In addition to the amounts allocated to preference customers, including the Purchaser, pursuant to subparagraph (1)(i) above, the Administrator shall determine prior to July 1, 1978, the amount, if any, of firm energy load carrying capability available on the Federal System in the Contract Year 1976, which is available for allocation but which is not allocated to such customers pursuant to such paragraph (1)(i). The Purchaser's allocation for any Contract Year may be additionally increased by the Administrator, effective on written notice served not less than 90 days prior to such Contract Year, to reflect increases in Firm Energy that he determines can be made available hereunder. At least 90 days prior to either such allocation the Administrator shall make available to the Purchaser, for timely comment, the criteria he intends to use to make such allocation.

BPA believes that this proposed policy, if implemented, would serve the public interest and efficiently utilize and promote widespread use in the Pacific Northwest of Federal firm energy.

Dated: September 27, 1979.

Sterling Munro,

Administrator.

[FR Doc. 79-30804 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

federal register

Friday
October 5, 1979

Part VII

Department of the Interior

Office of Surface Mining Reclamation and Enforcement

Determination of Completeness for Permanent Program Submission From the State of Montana

DEPARTMENT OF THE INTERIOR

Office of Surface Mining Reclamation and Enforcement

Determination of Completeness for Permanent Program Submission From the State of Montana

AGENCY: Office of Surface Mining Reclamation and Enforcement (OSM) U.S. Department of the Interior.

ACTION: Notice of Determination of Completeness of Submission.

SUMMARY: On August 3, 1979, the state of Montana submitted to OSM its proposed permanent regulatory program under the Surface Mining Control and Reclamation Act of 1977 (SMCRA). This notice announces the Regional Director's determination as to whether the Montana program submission contains each required element specified in the permanent regulatory program regulations. The Regional Director has concluded his review and has determined the Montana program submission is complete.

ADDRESSES: Written comments on the Montana program and a summary of the public meeting are available for public review, 8:00 a.m.–4:00 p.m., Monday through Friday, excluding holidays at: Office of Surface Mining Reclamation and Enforcement, Region V, Post Office Building, Room 225, 1823 Stout Street, Denver, Colorado 80202.

Copies of the full text of the proposed Montana program are available for review during regular business hours at the OSM Regional Office above and at the following offices of the State regulatory authority:

Montana Department of State Lands, 1625 11th Avenue, Capitol Station, Helena, Montana 59601.

Department of State Lands Field Office, 1245 North 29th Street, Billings, Montana 59101.

FOR FURTHER INFORMATION CONTACT: Sylvia Sullivan, Public Information Officer, Office of Surface Mining Reclamation and Enforcement, Post Office Building, Room 270, 1823 Stout Street, Denver, Colorado 80202.

SUPPLEMENTARY INFORMATION: On August 6, 1979, OSM received a proposed permanent regulatory program from the State of Montana. Pursuant to the provisions of 30 CFR Part 732, "Procedures and Criteria for Approval or Disapproval of State Program Submissions" (44 FR 15326–15328, March 13, 1979), the Regional Director, Region V, published notification of receipt of the program submission in the Federal Register of August 13, 1979 (44 FR 47414–47415) and in the following newspapers of general circulation within Montana:

Billings Gazette, Bozeman Chronicle, Montana Standard, Great Falls Tribune, Hamilton Republic, Havre News, Helena Independent Record, Kalispell Inter Lake, Livingston Enterprise, Miles City Star, and Missoulian.

The August 13, 1979, notice set forth information concerning public participation pursuant to 30 CFR 732.11. This information included a summary of the program submission, announcement of a public review meeting on September 12, 1979, in Helena, Montana to discuss the submission and its completeness, and announcement of a public comment period until September 12, 1979, for members of the public to submit written comments relating to the program and its completeness. Further information may be found in the permanent regulatory program regulations and Federal Register notice referenced above.

This notice is published pursuant to 30 CFR 732.11(b) and constitutes the Regional Director's decision on the completeness of the Montana program. Having considered public comments, testimony presented at the public review meeting and all other relevant information, the Regional Director has determined that the Montana submission does fulfill the content requirements for program submission under 30 CFR 731.14 and is therefore complete.

No later than November 20, 1979, the Regional Director will publish a notice in the Federal Register and in the following newspapers of general circulation in Montana initiating substantive review of the program submission:

Billings Gazette, Bozeman Chronicle, Montana Standard, Great Falls Tribune, Hamilton Republic, Havre News, Helena Independent Record, Kalispell Inter Lake, Livingston Enterprise, Miles City Star, and Missoulian.

The review will include an informal public hearing and written comment period. Procedures will be detailed in that notice. Further information concerning how that substantive review will be conducted may be found in 30 CFR 732.12.

The Office of Surface Mining is not preparing an environmental impact statement with respect to the Montana regulatory program, in accordance with Section 702(d) of SMCRA (30 U.S.C. § 1292(d)), which states that approval of State programs shall not constitue a major action within the meaning of Section 102(2)(C) of the National Environmental Policy Act.

Dated: October 1, 1979.

Donald A. Crane,

Regional Director.

[FR Doc. 79-31034 Filed 10-4-79; 8:45 am]

BILLING CODE 4310-05-M

federal register

Friday
October 5, 1979

Part VIII

Office of Management and Budget

Uniform Administrative Requirements for Grants-in-Aid to State and Local Governments; Circular A-102

OFFICE OF MANAGEMENT AND BUDGET

Circular A-102, "Uniform Administrative Requirements for Grants-in-Aid to State and Local Governments"

This notice revises OMB Circular A-102, "Uniform administrative requirements for grants-in-aid to State and local governments." The revision was based on a recommendation by the President's Cash Management Task Force, and brings the grant payment policies of the Circular into line with the cash management policies of the Department of the Treasury.

The Treasury regulations provide that Federal cash made available to recipients of grants shall be timed to coincide with their cash needs. However, in many cases Federal payments to recipients have included amounts that are withheld by the recipient from contractors to assure satisfactory completion of the contract. The time lapse from the point the recipient received payment and the contractor was paid in full has varied from thirty days to more than a year. This practice resulted in interest costs to the Federal Government that could have been avoided.

The revision requires that recipients shall not be reimbursed for amounts that are to be withheld to assure satisfactory completion of the work. The change is effective January 1, 1980. However, Federal grantor agencies may defer implementation to January 1, 1981, for recipients that must amend their laws in order to comply.

The proposed revision was published for comment in the Federal Register on October 18, 1978. In response to the publication, we received about 50 comments from Members of Congress, Federal agencies, State and local governments, associations, and others. There follows a summary of the major comments grouped by subject and our response to each.

Comment. Several commentators pointed out that the proposed revision would deprive them of the interest earned on the Federal payments.

Response. The present practice encourages the premature disbursement of Federal funds and results in increased interest costs to the Federal Government. It is estimaed that this amounts to about $12 million a year. The revision would end this, while continuing the policy of assuring that funds are available to grant recipients when needed by them to make payments.

Comment. Many commentators stated that the revision would require extensive changes in their accounting systems because, as originally drafted, the revision appeared to apply to all costs, and would have required conversion to cash basis accounting.

Response. We agreed with these comments and have modified the revision. As presented here, the revision will permit recipients to continue to bill on the accrued cost basis, handling retained amounts as adjustments in the billing system.

Comment. Some commentators stated that the proposed revision would require a change in State or local law.

Response. We agreed that time should be provided to permit any necessary changes in State or local law. As presented here, the revision authorizes agencies to defer implementation until January 1, 1981, to permit such changes.

The following is added to paragraph 5, Attachment J, *Grant Payment Requirements:* "With respect to payments to contractors, recipients shall not be reimbursed for amounts that are to be withheld to assure satisfactory completion of the work. These amounts will be paid when recipients make final payment including amounts withheld."

Further Information: For further information contact Mr. John J. Lordan, Chief, Financial Management Branch, Office of Management and Budget, New Executive Office Building, 726 Jackson Place, N.W., Washington, D.C. 20503, (202) 395-6823.

James T. McIntyre, Jr.,
Director.

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federal register

Friday
October 5, 1979

Part IX

Office of Management and Budget

Budget Rescission and Deferrals

OFFICE OF MANAGEMENT AND BUDGET

Budget Rescission and Deferrals

To the Congress of the United States

In accordance with the Impoundment Control Act of 1974, I herewith propose rescission of $113,673 in unneeded funds appropriated to the International Communication Agency, and report 31 deferrals of fiscal year 1980 funds totalling $1,003.2 million. The deferrals are primarily routine in nature and do not, in most cases, affect program levels.

The details of the rescission proposal and each deferral are contained in the attached reports.

Jimmy Carter

The White House,
October 1, 1979.

BILLING CODE 3110-01-M

CONTENTS OF SPECIAL MESSAGE
(in thousands of dollars)

Rescission #	Item	Budget Authority
	International Communication Agency:	
R80-1	Special International Exhibitions (Special Foreign Currency Program)	114
	SUBTOTAL, RESCISSION PROPOSAL	114

Deferral #	Item	Budget Authority
	Funds Appropriated to the President	
	International Security Assistance	
D80-1	Economic Support Fund	100,000
	Department of Agriculture:	
	Forest Service	
D80-2	Timber salvage sales	9,298
D80-3	Expenses, brush disposal	32,060
D80-4	Restoration of forest lands and improvements	38
	Department of Commerce:	
	National Oceanic and Atmospheric Administration	
D80-5	Construction	7,000
D80-6	Coastal zone management	20,000
D80-7	Promote and develop fishery products and research pertaining to American Fisheries.	2,400
D80-8	Fisheries loan fund	5,300
	Department of Defense-Military:	
D80-9	Military construction, all services	31,386
	Department of Defense-Civil:	
	Miscellaneous accounts	
D80-10	Wildlife conservation, all services	595
	Department of Energy:	
	Energy programs	
D80-11	Fossil energy construction	50,000
	Department of Health, Education, and Welfare:	
	Alcohol, Drug Abuse, and Mental Health Administration	
D80-12	Construction and renovation, St. Elizabeth's Hospital	23,314
	Human Development Services	
D80-13	White House Conferences on Aging and Families	4,649

CONTENTS OF SPECIAL MESSAGE (continued)

Deferral #	Item	Budget Authority
	Department of the Interior:	
	Heritage Conservation and Recreation Service	
D80-14	Land and water conservation fund...........	30,000
	Geological Survey	
D80-15	Payments from proceeds, sale of water......	39
	Bureau of Mines	
D80-16	Drainage of anthracite mines...............	1,137
	Department of Justice:	
	Federal Prison System	
D80-17	Buildings and facilities...................	22,853
	Department of State:	
D80-18	United States emergency refugee and migration assistance fund...................	5,650
	Department of Transportation:	
	Federal Aviation Administration	
D80-19	Civil supersonic aircraft development termination..............................	5,004
D80-20	Facilities and equipment (airport and airway trust fund)....................	138,211
	Urban Mass Transportation Administration	
D80-21	Urban Mass Transportation Fund.............	393,076
	Department of the Treasury:	
	Office of Revenue Sharing	
D80-22	State and local government fiscal assistance fund..........................	79,548
D80-23	State and local government fiscal assistance fund..........................	2,735 1/
	Bureau of the Mint	
D80-24	Construction of mint facilities............	3,230

1/ Outlays only.

CONTENTS OF SPECIAL MESSAGE (continued)

Deferral #	Item	Budget Authority
	Other Independent Agencies:	
	Federal Emergency Management Agency	
D80-25	Emergency planning, preparedness, and mobilization...........................	80
	Foreign Claims Settlement Commission	
D80-26	Payment of Vietnam prisoner of war claims..	1,800
	International Communication Agency	
D80-27	Acquisition and construction of radio facilities................................	10,973
	National Alcohol Fuels Commission	
D80-28	Salaries and expenses......................	250
	National Commission on Social Security	
D80-29	Salaries and expenses......................	250
	Navajo and Hopi Indian Relocation Commission	
D80-30	Salaries and expenses......................	5,300
	Tennessee Valley Authority	
D80-31	Tennessee Valley Authority Fund............	17,000
	SUBTOTAL, DEFERRALS......................	1,003,176
	TOTAL, RESCISSION PROPOSAL AND DEFERRALS...........................	1,003,290

SUMMARY OF SPECIAL MESSAGES
FOR FY 1980
(amounts in thousands of dollars)

	Rescissions	Deferrals
First special message..........	114	1,003,176 (in 31 deferrals)

NOTE: All amounts listed represent budget authority except for $2,734,554 in one general revenue sharing deferral of outlays only (D80-23).

Rescission Proposal No: R80-1

PROPOSED RESCISSION OF BUDGET AUTHORITY

Report Pursuant to Section 1012 of P.L. 93-344

Agency International Communication Agency Bureau	New budget authority (P.L. ____) $ ____ Other budgetary resources 113,673 Total budgetary resources 113,673
Appropriation title & symbol Special International Exhibitions (Special Foreign Currency Program) 67X0069	Amount proposed for rescission $113,673
OMB identification code: 67-9911-0-1-154 Grant program ☐ Yes ☒ No	Legal authority (in addition to sec. 1012): ☒ Antideficiency Act ☐ Other ____
Type of account or fund: ☐ Annual ☐ Multiple-year ____ (expiration date) ☒ No-year	Type of budget authority: ☒ Appropriation ☐ Contract authority ☐ Other ____

Justification: The United States International Communication Agency (ICA) was established by: (1) the United States Information and Educational Exchange Act of 1948, as amended (22 U.S.C. 1431 et seq.); (2) the Mutual Educational and Cultural Exchange Act of 1961 (22 U.S.C. 2451 et seq.); (3) Executive Order No. 11034 of June 25, 1962, as amended; and (4) Reorganization Plan No. 2 of 1977, to carry out international communication, cultural and educational exchange programs.

Prior to 1975, funds regularly were authorized and appropriated to the United States Information Agency (the predecessor agency to ICA) in the Special International Exhibitions (Special Foreign Currency Program) account to finance local currency expenses of international exhibitions with U.S.-owned currencies in excess of the normal requirements of the United States.

Beginning in 1975, all appropriations for international exhibitions were made to the Special International Exhibitions account (now part of the Salaries and Expenses account). This change was made because U.S.-owned local currencies in excess of normal requirements of the United States were no longer available for those countries where these activities were conducted.

In each of the intervening years since 1975, appropriate reprogramming opportunities for this small remaining balance of $113,673 in the Special International Exhibitions (Special Foreign Currency Program) account were anticipated but never materialized. Therefore, these funds are proposed for rescission.

Estimated Effect: There are no programmatic or budgetary effects resulting from this rescission proposal.

Outlay Effect: There is no outlay effect of this rescission proposal because the funds could not be used if made available.

R80-1

TITLE V - RELATED AGENCIES

United States Information Agency

Special International Exhibitions
(Special Foreign Currency Program)

Of the unobligated balances appropriated under this head in Public Law 92-544 and Public Law 93-162, $113,673 are rescinded.

Deferral No: D80-1

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency Funds Appropriated to the President	New budget authority (P.L. ____) $ ____
Bureau International Security Assistance	Other budgetary resources 215,000,000
Appropriation title & symbol Economic Support Fund[1/] 11X1037	Total budgetary resources 215,000,000
	Amount to be deferred: Part of year $ ____ Entire year 100,000,000
OMB identification code: 11-1006-0-1-151	Legal authority (in addition to sec. 1013): ☒ Antideficiency Act ☐ Other ____
Grant program ☐ Yes ☒ No	
Type of account or fund: ☐ Annual ☐ Multiple-year ____ (expiration date) ☒ No-year	Type of budget authority: ☒ Appropriation ☐ Contract authority ☐ Other ____

Justification:

Pursuant to the Foreign Assistance Act of 1961, as amended, the President is authorized to "furnish assistance to friendly countries...on such terms as he may determine, in order to support or promote economic or political stability."

The Supplemental Appropriations Act, 1979 (P.L. 96-38), provided $300 million in economic assistance for Egypt as part of a package in support of the Treaty of Peace between Egypt and Israel. As presented to the Congress in testimony on the peace package, the special assistance for Egypt would be obligated over a three-year period. In 1979, $85 million was obligated, and another $115 million is planned for obligation in 1980. Accordingly, $100 million is deferred until 1981.

This deferral action is taken in accordance with the Antideficiency Act (31 U.S.C. 665).

Estimated Effects:

This deferral will have no budgetary or programmatic impact.

Outlay Effects:

There is no outlay effect resulting from this deferral.

1/ This account was the subject of a similar deferral in FY 1979.

Deferral No: D80-2

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Agriculture Bureau: Forest Service Appropriation title & symbol: Timber Salvage Sales[1/] 12X5204	New budget authority (P.L. ______) $ ______ Other budgetary resources 20,707,732 Total budgetary resources 20,707,732 Amount to be deferred: Part of year $ ______ Entire year 9,297,732
OMB identification code: 12-5204-0-2-302 Grant program ☐ Yes ☒ No	Legal authority (in addition to sec. 1013): ☒ Antideficiency Act ☐ Other ______
Type of account or fund: ☐ Annual ☐ Multiple-year ______ (expiration date) ☒ No-year	Type of budget authority: ☒ Appropriation ☐ Contract authority ☐ Other ______

Justification: The timber salvage sales fund was authorized by the National Forest Management Act of 1976 to increase the capability of the Forest Service to offer insect-infested, dead, damaged, or fallen timber for sale. Receipts from the sale of such timber are deposited in a special fund and are available until expended to cover the costs of design, engineering, and supervision of the construction of needed roads, as well as the cost to the Forest Service of sale preparation and supervision of actual harvesting.

Present program plans for timber salvage sales require a resource level of $11,410,000. The remaining $9,297,732 is being deferred in accordance with the Antideficiency Act (31 U.S.C. 665) which authorizes the establishment of reserves for contingencies. This action is being taken because of the time lag between the deposit of receipts from salvage sales and the expenditure of funds to cover costs associated with making additional sales. Efficient program planning and accomplishment is facilitated by administering a stable program well within the funds available in any one year for this purpose.

Estimated Effect: There are no programmatic or budgetary effects that result from this deferral action. The reserve reflects the time lag between deposit of receipts from salvage sales and the expenditure of these funds to cover the costs of additional sales.

Outlay Effect: There is no outlay effect of this deferral because the funds could not be used if made available.

1/ This account was the subject of a similar deferral in FY 1979.

Deferral No: D80-3

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Agriculture	New budget authority (P.L. 16 U.S.C. 490) $ 40,509,000
Bureau: Forest Service	Other budgetary resources 37,551,072
Appropriation title & symbol: Expenses, Brush Disposal 1/ 12X5206	Total budgetary resources 78,060,072
	Amount to be deferred: Part of year $; Entire year 32,060,072
OMB identification code: 12-9922-0-2-302	Legal authority (in addition to sec. 1013): [X] Antideficiency Act [ ] Other
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual [ ] Multiple-year (expiration date) [X] No-year	Type of budget authority: [X] Appropriation [ ] Contract authority [ ] Other

Justification: Purchasers of National Forest timber deposit the estimated cost to the Forest Service of the disposing of brush and other debris resulting from their cutting operations pursuant to 16 U.S.C. 490. The deposits becoming available in the current year are estimated and the related disposal operations are planned for the following year. Efficient program planning and accomplishment is facilitated by operating a stable program well within the funds available in any one year for this purpose. An apportionment of $46.0 million has been made to the Forest Service for this program in 1980. The current fiscal year reserve of $32.1 million is established pursuant to the Antideficiency Act (31 U.S.C. 665) as a reserve for contingencies.

Disposal operations related to deposits made during certain periods of the year cannot be initiated until weather conditions permit. Thus, seasonal factors frequently require deferring the use of deposits until the following fiscal year.

Estimated Effect: There are no programmatic or budgetary effects that result from this deferral action. Rather, the reserve merely reflects the seasonal nature of program funding requirements.

Outlay Effect: There is no outlay effect of this deferral because the funds could not be used if made available.

1/ This account was the subject of a similar deferral in FY 1979.

Deferral No: D80-4

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency Department of Agriculture	New budget authority (P.L. 16 USC 579C) $ 50,000
Bureau Forest Service	Other budgetary resources 48,038
Appropriation title & symbol Restoration of Forest Lands and Improvements 1/ 12X5215	Total budgetary resources 98,038
	Amount to be deferred: Part of year $ Entire year 38,038
OMB identification code: 12-9922-0-2-302	Legal authority (in addition to sec. 1013): [X] Antideficiency Act [ ] Other
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual [ ] Multiple-year ______ (expiration date) [X] No-year	Type of budget authority: [X] Appropriation [ ] Contract authority [ ] Other

Justification: Monies are collected for this program pursuant to the Act of June 30, 1958 (16 USC 579C) from timber purchasers or permittees who fail to complete the restoration work required under the timber sale contract or by terms of the permit. These funds are used by the Forest Service for any improvement, protection, or rehabilitation of the land made necessary by the action which led to the cash settlement of the contract or permit.

This deferral is necessary because of the time and planning required for either completing the work for which the funds were collected or for transferring the collections to the general fund of the U.S. Treasury in those cases where the work has been completed.

This deferral action is taken in accordance with the Antideficiency Act (31 USC 665).

Estimated Effect: There are no programmatic or budgetary effects that result from this deferral action. Rather, the reserve merely reflects the unpredictable nature of program funding requirements.

Outlay Effect: There is no outlay effect of this deferral because the funds would not be used if made available.

1/ This account was the subject of a similar deferral in FY 1979.

Deferral No: D80-5

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Commerce	New budget authority (P.L. ______) $ ______
Bureau: National Oceanic and Atmospheric Administration	Other budgetary resources 60,000,000
Appropriation title & symbol: Construction 13x1452 1/	Total budgetary resources 60,000,000
	Amount to be deferred: Part of year $ ______; Entire year 7,000,000
OMB identification code: 13-1452-0-1-306	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ______
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual; [ ] Multiple-year ______ (expiration date); [X] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ______

Justification: Public Law 96-38, enacted July 25, 1979, included a supplemental appropriation of $60,000,000 to fully fund the construction of the National Oceanic and Atmospheric Administration Western Regional Center in Seattle, Washington. Present program plans call for the obligation of $53,000,000 of this amount in FY 1980. The remaining $7,000,000 for construction of the Reception Center, demolition of the existing control tower and final site improvements is planned for obligation in FY 1981 and is deferred for the remainder of the fiscal year. This deferral is consistent with congressional intent to provide no-year funding for this project and is taken under the provisions of the Antideficiency Act (31 U.S.C. 665).

Estimated Effect: The amount deferred could not be economically used, if made available in FY 1980, because of the planned construction cycle.

Outlay Effect: The outlay plan for construction of the Sand Point facility anticipates that construction will take place over a period of years, thus this deferral will not affect outlays for FY 1980.

1/ This account was the subject of a similar deferral in FY 1979.

Deferral No: D80-6

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Commerce	New budget authority (P.L. ____) $ ____
Bureau: National Oceanic and Atmospheric Administration	Other budgetary resources 28,000,000
Appropriation title & symbol: Coastal Zone Management 13x1451	Total budgetary resources 28,000,000
	Amount to be deferred: Part of year $ ____; Entire year 20,000,000
OMB identification code: 13-1451-0-1-302	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ____
Grant program [X] Yes [ ] No	
Type of account or fund: [ ] Annual; [ ] Multiple-year ____ (expiration date); [X] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ____

Justification: This appropriation provides for administration, management, beneficial use, protection, and development of the land and water resources of the Nation's coastal zone, by providing grants to States for the planning and management of their coastal areas. The rate of applications for these funds from the States is significantly lower than previously anticipated. Of the funds provided in FY 1979 and previous years for energy impact formula grants, it is estimated that $20,000,000 will not be required to support the planned program in FY 1980. Therefore, these funds are deferred in accordance with the Antideficiency Act (31 U.S.C. 665).

Estimated Effect: This deferral has no effect on the planned program for FY 1980, since these funds would not be used if made available.

Outlay Effect: There is no effect of this deferral on planned outlays.

Deferral No: D80-7

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Commerce	New budget authority (7 U.S.C. 612C) $ 26,679,106
Bureau: National Oceanic and Atmospheric Administration	Other budgetary resources 159,000
Appropriation title & symbol: Promote and Develop Fishery Products and Research Pertaining to American Fisheries 13x5139 1/	Total budgetary resources 26,838,106
	Amount to be deferred: Part of year $; Entire year 2,400,000
OMB identification code: 13-5139-0-2-376	Legal authority (in addition to sec. 1013): ☐ Antideficiency Act ☐ Other
Grant program ☐ Yes ☒ No	
Type of account or fund: ☐ Annual ☐ Multiple-year (expiration date) ☒ No-year	Type of budget authority: ☐ Appropriation ☐ Contract authority ☒ Other 7 U.S.C. 612C

Justification: An amount equal to 30% of the gross receipts from custom duties on fishery products is appropriated for fishery products resources research and assessment, and American fisheries resource management and development. These funds supplement funds appropriated to National Oceanic and Atmospheric Administration for these purposes under the Operations, research, and facilities appropriation.

The amount being deferred, $2,400,000, represents the excess amount of receipts over the cost of currently planned program activities in FY 1980. Because plans have not yet been developed for use of this amount, the funds are being deferred. Final decisions on how these funds would be used have not been reached and, thus, the funds could not be used effectively if made available for obligation.

Estimated Effects: This deferral has no effect on the program as currently planned for FY 1980.

Outlay Effect: There is no outlay effect of this deferral because the funds would not be used if made available.

1/ This account was the subject of a similar deferral during FY 1979.

Deferral No: D80-8

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency Department of Commerce	New budget authority (P.L. ____) $____
Bureau National Oceanic and Atmospheric Administration	Other budgetary resources 6,000,000
Appropriation title & symbol Fisheries Loan Fund 1/ 137/04317	Total budgetary resources 6,000,000
	Amount to be deferred: Part of year $ 5,300,000 Entire year -0-
OMB identification code: 13-4317-03-376	Legal authority (in addition to sec. 1013): ☒ Antideficiency Act
Grant program ☐ Yes ☒ No	☐ Other ____
Type of account or fund: ☐ Annual ☒ Multiple-year September 30, 1980 (expiration date) ☐ No-year	Type of budget authority: ☒ Appropriation ☐ Contract authority ☒ Other 16 U.S.C. 742C

Justification:

This fund was established pursuant to the Fish and Wildlife Act of 1956, as amended (16 U.S.C. 742c). Its purpose is to provide funds for loans to segments of the fishing industry unable to obtain commercial loans on reasonable terms for financing the cost of purchasing, constructing, equipping, maintaining, repairing or operating new or used fishing vessels or gear.

In 1965, the Act was amended to require the National Oceanic and Atmospheric Administration (NOAA) to pay interest to the Treasury on the difference between the available funds and the cash balance at the end of the year. The current program covers the 1980 interest liability of $680,000 and provides $20,000 for the care and preservation of collateral throughout the year. Of the total budgetary resources in the fund, only these amounts are presently planned for expenditure in 1980 to support the estimated program requirements.

On February 20, 1973, the Administrator of NOAA declared a moratorium on accepting further loan applications effective March 1, 1973, due to a level of loans outstanding and loan applications pending that exceeded the Fund's capital. Additionally, the General Accounting Office concluded in a report issued February 22, 1973, that loans made from the Fisheries Loan Fund (1) allowed the continued use of inefficient vessels rather than improving vessels and equipment for more efficient and profitable fishing, and (2) maintained or added vessels to segments of the fishing industry that were considered to have excess, but not necessarily efficient, harvesting capacity. GAO recommended that the Secretary of Commerce develop criteria for evaluating vessel

1/ This account was the subject of a similar deferral during FY 1979.

D80-8

efficiency and priorities for directing these program funds.

The Department is considering possible legislative options affecting the Fisheries Loan Fund. Any legislative changes would be transmitted in time for full consideration during the Second Session of the 96th Congress. These funds are deferred pending Departmental consideration and related congressional actions.

Estimated Effects

Under the existing laws and regulations the proposed deferral has no effect on the Fisheries Loan Fund activities as planned for fiscal year 1980.

Outlay Effects:

No outlay effect results from this deferral action.

Deferral No: D80-9

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Defense - Military	New budget authority (P.L. ______) $ ______
Bureau	Other budgetary resources 1,578,715,:
Appropriation title & symbol: See coverage section below	Total budgetary resources 1,578,715,:
	Amount to be deferred: Part of year $ 31,386, ; Entire year ______
OMB identification code: See coverage section below	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ______
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual; [X] Multiple-year September 30, 1983 (expiration date); [ ] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ______

Coverage 1/

Appropriation	Symbol	OMB Identification Code	Amount Deferred
Military construction, Army	219/32050	21-2050-0-1-051	$ 12,000,000
Military construction, Navy	179/31205	17-1205-0-1-051	0
Military construction, Air Force	579/33300	57-3300-0-1-051	0
Military construction, Defense Agencies	979/30500	97-0500-0-1-051	16,644,000
Military construction, Army National Guard	219/32085	21-2085-0-1-051	0
Military construction, Air National Guard	579/33830	57-3830-0-1-051	0
Military construction, Army Reserve	219/32086	21-2086-0-1-051	1,364,000
Military construction, Naval Reserve	179/31235	17-1235-0-1-051	1,378,000
Military construction, Air Force Reserve	579/33730	57-3730-0-1-051	0
			$ 31,386,000

1/ These accounts were the subject of a similar deferral during fiscal year 1979.

D80-9

Justification

The above amounts in the listed five-year appropriations are currently deferred under provisions of the Antideficiency Act (31 U.S.C. 665) which authorize the establishment of reserves for contingencies.

The Congress made appropriations for this purpose available for five years beginning with fiscal year 1979. Previously, these appropriations were available for obligation until expended. The above funds are deferred due to administrative delays, such as project designs not being completed and incomplete coordination of projects with either other Federal agencies or local government agencies. Funds will be apportioned for individual projects throughout the year upon completion of project design and/or coordination.

Estimated Effects

These deferrals have no programmatic or budgetary effect because the funds could not be obligated at this time, even if they were made available.

Outlay Effect

There is no outlay effect resulting from this deferral since the funds could not be used if made available.

Deferral No: D80-10

DEFERRAL OF BUDGET AUTHORITY

Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Defense - Civil	New budget authority (16 U.S.C. 670 f (a)) $ 967,000
Bureau	Other budgetary resources 595,166
Appropriation title & symbol: See coverage section below	Total budgetary resources 1,562,166
	Amount to be deferred: Part of year $ ____; Entire year 595,166
OMB identification code: See coverage section below	Legal authority (in addition to sec. 1013): [x] Antideficiency Act. [ ] Other ____
Grant program: [ ] Yes [x] No	
Type of account or fund: [ ] Annual; [ ] Multiple-year ____ (expiration date); [x] No-year	Type of budget authority: [x] Appropriation; [ ] Contract authority; [ ] Other ____

Coverage*

Wildife Conservation, etc., Military Reservations, Army, 21x5095, 21-1500-0-1-303	$450,000
Wildife Conservation, etc., Military Reservations, Navy, 17x5095, 17-1501-0-1-303	103,000
Wildife Conservation, etc., Military Reservations, Air Force, 57x5095, 57-1502-0-1-303	42,166
	$595,166

Justification

These are permanent appropriations. The budgetary resources consist of anticipated receipts and unobligated balances generated from hunting and fishing fees collected on military reservations, pursuant to 16 U.S.C. 670. They may be used only in accordance with the purpose of the law--to carry out a program of natural resource conservation.

Since apportionments have been made for all known program requirements, prudent financial management requires the deferral of the balance of the funds, which could not be used effectively during the current year even if made available for obligation. These funds are being deferred under the provisions of the Antideficiency Act (31 U.S.C. 665). Full apportionment is not requested by the Services because (1) installations may be accumulating funds over a period of time to fund a major project, and (2) there is a seasonal relationship between the collection of fees and their subsequent expenditure. Most of the fees are collected during the winter and spring months, while most of the program work is performed during the summer and fall months. This necessitates that funds collected in a prior year be deferred in order to be available to finance the program during the summer and fall months. Additional amounts will be apportioned if program requirements are identified.

* These accounts were the subject of a similar deferral during fiscal year 1979.

D80-10

Estimated Effects

These deferrals have no programmatic or budgetary effect because the funds could not be obligated if made available.

Outlay Effect

There is no outlay effect of this deferral because the funds could not be used if made available.

Deferral No: D80-11

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Energy	New budget authority (P.L. ______) $ ______
Bureau: Energy Programs	Other budgetary resources 162,570,000
Appropriation title & symbol: Fossil Energy Construction 1/ 89X0214	Total budgetary resources 162,570,000
	Amount to be deferred: Part of year $ 50,000,000; Entire year ______
OMB identification code: 89-0214-0-1-271	Legal authority (in addition to sec. 1013): ☐ Antideficiency Act ☐ Other ______
Grant program ☐ Yes ☒ No	
Type of account or fund: ☐ Annual ☐ Multiple-year ______ (expiration date) ☒ No-year	Type of budget authority: ☒ Appropriation ☐ Contract authority ☐ Other ______

Justification: These funds were appropriated in FY 1979 and prior years for the construction of a low/medium BTU coal gasification demonstration plant. Present scheduling calls for reaching a decision to proceed with construction of the plant in December 1979, pending completion of two conceptual designs which will provide necessary environmental and economic assessments. These funds are deferred pending the results of this decision.

This deferral action is consistent with the recommendations contained in both House and Senate report language accompanying H.R. 2439, the Budget Rescission Bill, 1979, which was signed into law on April 9, 1979 (P.L. 96-7).

Estimated Effect: Deferral of these funds will have no impact on the construction schedule since the conceptual design phase of the project is not expected to be completed until December 1979, and a selection of one of the two designs could not be made until the second quarter of FY 1980.

Outlay Effect: There is no effect on outlays of this deferral.

1/ This account was the subject of a similar deferral in FY 1979.

Deferral No: D80-12

DEFERRAL OF BUDGET AUTHORITY

Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Health, Education, and Welfare	New budget authority (P.L. ____) $ ____
Bureau: Alcohol, Drug Abuse, and Mental Health Administration	Other budgetary resources 54,480,045
Appropriation title & symbol: Construction and Renovation, St. Elizabeth's Hospital 1/ 75X1312	Total budgetary resources 54,480,045
	Amount to be deferred: Part of year $ ____; Entire year 23,314,000
OMB identification code: 75-1312-0-1-551	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ____
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual; [ ] Multiple-year ____ (expiration date); [X] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ____

Justification: Funds were provided in the Second Supplemental Appropriations Act, 1978 (P.L. 95-355), for the purpose of upgrading St. Elizabeth's Hospital to meet accreditation standards. In August 1979, St. Elizabeth's regained a one-year accreditation from the Joint Commission on Accreditation of Hospitals, contingent upon implementation of the renovation plans. Plans and designs for renovation and reconstruction are in process. This deferral represents amounts not required for obligation in 1980, based on the current renovation schedule for the hospital. This deferral is consistent with congressional intent to provide no-year funding for this project, and is taken under the provisions of the Antideficiency Act (31 U.S.C. 665).

Estimated Effect: The amount deferred could not be economically used this fiscal year, if made available, due to the planned renovation schedule.

Outlay Effect: There is no outlay effect of this deferral.

1/ This account was the subject of a similar deferral during FY 1979.

Deferral No: D80-13

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency Department of Health, Education, and Welfare	New budget authority (P.L. ____) $ ____
Bureau	Other budgetary resources 6,836,010
Appropriation title & symbol 75X1636 Human Development Services 1/ (White House Conference on Aging and White House Conference on Families)	Total budgetary resources 6,836,010
	Amount to be deferred: Part of year $ 4,648,510 Entire year ____
OMB identification code: 75-1636-0-1-500	Legal authority (in addition to sec. 1013): ☐ Antideficiency Act ☐ Other ____
Grant program ☐ Yes ☒ No	
Type of account or fund: ☐ Annual ☐ Multiple-year ____ (expiration date) ☒ No-year	Type of budget authority: ☒ Appropriation ☐ Contract authority ☐ Other ____

P.L. 96-38 provided a $3,000,000 appropriation for a White House Conference on Aging to be held in December 1981 for the purpose of developing recommendations for a comprehensive national policy on aging. These funds are to remain available until expended and are intended to cover the entire cost of planning and carrying out this conference through fiscal year 1981.

P.L. 95-205 provided a $3,000,000 appropriation for a White House Conference on Families to be held to explore the problems of the American family and examine the impact of our institutions, public policies and laws, employment, media, and voluntary organizations on the capability of families to meet basic needs and respond to changes and increased pressures produced by our society. These funds are also to remain available until expended and are intended to cover the entire costs of planning and carrying out this conference through fiscal year 1981.

This deferral action is being taken while HEW develops a financial plan for funding the Conferences during the next two fiscal years. Sufficient funds have been made available for administrative costs for these activities in the interim.

Estimated Effects

There is no programmatic or budgetary effect resulting from this deferral.

Outlay Effect

There is no outlay effect resulting from this deferral.

1/ This account was the subject of a similar deferral during FY 1979.

Deferral No: D80-14

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of the Interior Bureau: Heritage Conservation and Recreation Service	New budget authority (P.L. 95-74; 16 USC 460L) $ 30,000,000 Other budgetary resources 245,800,000 Total budgetary resources 275,800,000
Appropriation title & symbol Land and Water Conservation Fund 1/ 14X5005	Amount to be deferred: Part of year $ ____ Entire year 30,000,000
OMB identification code: 14-5005-0-2-303 Grant program ☐ Yes ☒ No	Legal authority (in addition to sec. 1013): ☒ Antideficiency Act ☐ Other ____
Type of account or fund: ☒ Annual ☐ Multiple-year ____ (expiration date) ☒ No-year	Type of budget authority: ☒ Appropriation ☒ Contract authority ☐ Other ____

Justification: Under existing law (16 USC 460L(10a)), $30 million of contract authority becomes available each fiscal year to the Land and Water Conservation Fund in addition to regular appropriations. The authority is made available by the Congress for use specifically as an anti-escalation measure in purchasing authorized Federal recreation land (P.L. 90-401; Senate Report 90-1071, to accompany S.1401). This authority was last used in 1969 and 1970. Thus, the contract authority has lapsed in fiscal years 1971-1979. The funds will be utilized in the future, as in the past, on a special case basis for emergency situations consistent with our understanding of congressional intent.

In accordance with provisions of the Antideficiency Act (31 U.S.C. 665), the $30 million has been deferred. This contract authority lapses at the end of each fiscal year in which it is not used. An equal amount becomes available at the beginning of the next fiscal year.

The other funds in this account are the estimated prior-year balances of direct appropriations that have been made available for obligation.

Estimated Effect: This reserve for contingencies has no fiscal, economic or budgetary effect in the current year. The funds would be made available and obligated only in unforeseeable circumstances.

Outlay Effect: There is no outlay effect of this deferral because the funds would not be used if made available.

1/ This account was the subject of a similar deferral during FY 1979.

Deferral No: D80-15

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of the Interior	New budget authority (P.L. ____) $ ____
Bureau: Geological Survey	Other budgetary resources 39,000
Appropriation title & symbol: Payments from Proceeds, Sale of Water 1/ 14X5662	Total budgetary resources 39,000
	Amount to be deferred: Part of year $ ____; Entire year 39,000
OMB identification code: 14-5662-0-2-301	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ____
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual; [ ] Multiple-year ____ (expiration date); [X] No-year	Type of budget authority: [ ] Appropriation; [ ] Contract authority; [X] Other Permanent, indefinite, special

Justification: Section 40(d) of the Mineral Leasing Act of 1920 (30 U.S.C. 229(a)) provides that when lessees or operators drilling for oil or gas on public lands strike water, water wells may be developed by the Department from the proceeds from sale of water from existing wells. Receipts have been accruing to this permanent account at the rate of about $3,000 per year. At the start of fiscal year 1965, the account had an unobligated balance of $16,000. It is estimated that by the start of fiscal year 1980, the unobligated balance will be $39,000. None of these receipts has been obligated over the past ten years and none is planned for obligation in fiscal year 1980 because the total available is too small to be put to practical use for the purpose designated by law. Deferral is planned because funds could not be used effectively during the current period even if made available for obligation. This reserve action is taken pursuant to the Antideficiency Act (31 U.S.C. 665).

Estimated Effect: There will be no programmatic or outlay impact in fiscal year 1980 since the receipts will continue to accrue but will remain unobligated until such time as an amount is available which can be used for effective purposes.

Outlay Effect: There is no outlay effect of this deferral because the funds could not be used if made available.

1/ This account was the subject of a similar deferral during FY 1979.

Deferral No: D80-16

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency Department of the Interior	New budget authority $ --- (P.L. ______) Other budgetary resources 1,337,000 Total budgetary resources 1,337,000
Bureau Bureau of Mines	
Appropriation title & symbol Drainage of Anthracite Mines 1/ 14X0956	Amount to be deferred: Part of year $ --- Entire year 1,137,000
OMB identification code: 14-0956-0-1-306	Legal authority (in addition to sec. 1013): [X] Antideficiency Act [X] Other Matching grant provision of P.L. 84-219 (69 Stat 460)
Grant program [X] Yes [ ] No	
Type of account or fund: [ ] Annual [ ] Multiple-year ______ (expiration date) [X] No-year	Type of budget authority: [X] Appropriation [ ] Contract authority [ ] Other ______

Justification: Funds totalling $200,000 have been apportioned for this account to match funds anticipated to be made available by the Commonwealth of Pennsylvania for water monitoring stations and for sealing and other public health and safety projects. The remaining unobligated balance has been deferred because the Commonwealth of Pennsylvania is not expected to provide further matched funding during the year.

Estimated Effect: No FY 1980 program impact will result from deferral. These funds are anticipated to be deferred through September 30, 1980.

Outlay Effect: There is no outlay effect of this deferral because the funds could not be used if made available.

1/ This account was the subject of a similar deferral during FY 1979.

Deferral No: D80-17

DEFERRAL OF BUDGET AUTHORITY

Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Justice	New budget authority (P.L. ______) $ ______
Bureau: Federal Prison System	Other budgetary resources 55,253,415
Appropriation title & symbol: Buildings and Facilities 1/ 15X1003	Total budgetary resources 55,253,415
	Amount to be deferred: Part of year $ 6,200,000; Entire year 16,653,300
OMB identification code: 15-1003-0-1-753	Legal authority (in addition to sec. 1013): [X] Antideficiency Act ($16,653,300); [ ] Other ______
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual; [ ] Multiple-year ______ (expiration date); [X] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ______

Justification: This appropriation finances planning, acquisition of sites, and construction of new penal and correctional facilities as well as construction, remodeling, and equipping of necessary buildings and facilities at existing penal and correctional institutions. Projects are undertaken to reduce overcrowding, close old and antiquated penitentiaries, and provide a safe and humane environment for staff and inmates. These funds were appropriated in the Departments of State, Justice, and Commerce, the Judiciary and Related Agencies Appropriation Act of 1979 and previous years. Due to the time required for planning, site acquisition, design efforts, and selection of contractors, it is not possible to complete the construction, renovation, and rehabilitation associated with all of these projects during FY 1980. The deferral of funds for the entire year, totalling $16,653,000, is consistent with congressional intent to provide no-year funding for the total cost of these projects and is taken under provisions of the Antideficiency Act (31 U.S.C. 665).

This deferral also includes $6.2 million for the Detroit Metropolitan Correctional Center (MCC). These funds are deferred pending an OMB-initiated review (now underway) of a Justice Department decision which found that the facility was not needed.

Estimated Effect: The amount deferred for the entire year could not be economically used, if made available, in fiscal year 1980, because of the planned and phased procurement, construction and installation cycle. The effect of the part-of-year deferral is to preserve these funds for use until a final decision is made concerning whether or not to build the Detroit MCC.

Outlay Effect: There is no outlay effect of this deferral.

1/ This account was the subject of a deferral during FY 1979.

Deferral No: D80-18

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of State	New budget authority (P.L. ____) $ ____
Bureau	Other budgetary resources 5,650,000
Appropriation title & symbol: United States Emergency Refugee and Migration Assistance Fund, Executive 1/ 11X0040	Total budgetary resources 5,650,000
	Amount to be deferred: Part of year $ 5,650,000; Entire year ____
OMB identification code: 11-0040-0-1-151	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ____
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual; [ ] Multiple-year ____ (expiration date); [X] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ____

Justification: Section 501(a) of the Foreign Relations Authorization Act, Fiscal Year 1976, Public Law 94-141, approved November 29, 1975, amended section 2(c) of the Refugee and Migration Assistance Act of 1962 (22 U.S.C. 2601) by authorizing a fund not to exceed $25 million to enable the President to provide emergency assistance for unexpected urgent refugee and migration needs.

By Executive Order No. 11922 of June 16, 1976, the President allocated all funds appropriated to him for the Emergency Fund to the Secretary of State but reserved to himself the determination of assistance to be furnished and the designation of refugees to be assisted by the Fund.

Consistent with the President's authority set out in Executive Order No. 11922 and to achieve the most economical use of budgetary resources, the $5,650,000 of unobligated balances in the Fund as of October 1, 1979 have been deferred. It is anticipated that reapportionments may be made on a case-by-case basis as the President determines assistance to be furnished and designates refugees to be assisted by the Fund.

This deferral action is taken in accordance with the Antideficiency Act (31 U.S.C. 665).

Estimated Effect: There are no programmatic or budgetary effects resulting from this deferral.

Outlay Effect: No effect on outlays results from this deferral action.

1/ This account was the subject of a similar deferral during FY 1979.

Deferral No: D80-19

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Transportation	New budget authority (P.L. ____) $ ---
Bureau: Federal Aviation Administration	Other budgetary resources 5,003,623
Appropriation title & symbol: Civil Supersonic Aircraft Development Termination 69X0106; Civil Supersonic Aircraft Development 1/ 69X1358	Total budgetary resources 5,003,623
	Amount to be deferred: Part of year $ ---; Entire year 5,003,623
OMB identification code: 69-0106-0-1-402	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ____
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual; [ ] Multiple-year ____ (expiration date); [X] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ____

Coverage	Total Budgetary Resources Available and Deferred
Civil Supersonic Aircraft Development	$5,001,359
Civil Supersonic Aircraft Development Termination	2,264
TOTAL	$5,003,623

Justification: These accounts finance the termination of the supersonic transport development program. The total cost of settlement of contractor claims and closeouts, airline refunds, completion of specifically designated technology programs, and necessary governmental administrative costs incidental to these activities is included. These funds were appropriated by the Department of Transportation and Related Agencies Appropriation Acts, 1971 and 1972. Because of the difficulty in ending such a complex and massive undertaking, termination has taken a number of years. Settlement is being accomplished as quickly as possible consistent with the legitimate claims of the contractors and the protection of government interests.

Estimated Effect: This deferral action has no programmatic or budgetary effect.

Outlay Effect: There is no outlay effect of this deferral because the funds could not be used if made available.

1/ These accounts were the subject of a similar deferral during FY 1979.

Deferral No: D80-20

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Transportation	New budget authority (P.L. ______) $ ---
Bureau: Federal Aviation Administration	Other budgetary resources 315,211,075
Appropriation title & symbol: Facilities and Equipment (Airport and Airway Trust Fund), FAA 1/ 69X8107 698/08107 699/18107	Total budgetary resources 315,211,075
	Amount to be deferred: Part of year $ --- ; Entire year 138,211,075
OMB identification code: 69-8107-0-7-402	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ______
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual; [X] Multiple-year 698/08107 Sept. 30, 1980 2/, 699/18107 Sept. 30, 1981 (expiration date); [X] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ______

Justification: Funds from this account are used to procure specific congressionally-approved facilities and equipment for the expansion and modernization of the national airway system. Projects financed from this account include construction of buildings and purchase of new equipment for new or improved air traffic control towers, automation of the en route airway control system and expansion and improvement in the navigational and landing aid systems. These funds were appropriated in the Department of Transportation and Related Agencies Appropriation Acts of 1979 and prior years. The estimated total cost for each project is included in the budget submission and appropriation for the year in which it is requested. Because of the lengthy procurement and construction time for interrelated new facilities and complex equipment systems, it is not possible to obligate all funds necessary to complete each project in the year funds are appropriated. Therefore, it is necessary to apportion funds so that sufficient resources will be available in future periods to complete these projects. This deferral action is consistent with the congressional intent to provide multi-year funding for the total costs of these projects and is taken under provisions of the Antideficiency Act (31 U.S.C. 665) which authorize the establishment of reserves for contingencies.

Estimated Effect: This deferral action is consistent with the normal operation of this program. The amount deferred could not be economically used if made available in FY 1980 because of the planned multi-year procurement, construction, and installation cycle.

Outlay Effect: There is no outlay effect of this deferral because the funds could not be used if made available.

1/ This account was the subject of a similar deferral in FY 1979.
2/ None of these funds are deferred.

Deferral No: D80-21

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of Transportation	New budget authority (P.L. ______) $ ______
Bureau: Urban Mass Transportation Administration	Other budgetary resources 2,188,725,942
Appropriation title & symbol: Urban Mass Transportation Fund (Interstate Transfers) 69X1119 1/	Total budgetary resources 2,188,725,942
	Amount to be deferred: Part of year $ ______ ; Entire year 393,076,274
OMB identification code: 69-1119-0-1-401	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ______
Grant program [X] Yes [ ] No	
Type of account or fund: [ ] Annual; [ ] Multiple-year ______ (expiration date); [X] No-year	Type of budget authority: [ ] Appropriation; [X] Contract authority; [ ] Other ______

Justification: The Interstate transfer grant program was authorized by the Federal-Aid Highway Act of 1973, as amended. It provides Federal financing to allow States and localities to withdraw a planned Interstate highway segment, and substitute locally planned and programmed public transportation needs. These funds are available through the Department of Transportation and Related Agencies Appropriations Acts of 1979 and prior years, and the Federal-Aid Highway Acts of 1973 and 1976.

A 1980 program level of $700 million is planned. This is equivalent to the 1979 program level and is consistent with both congressional action thus far on the 1980 appropriations bill and the President's 1980 budget request. At this time, $575.5 million is being made available, consisting of $255.5 million in carryover balances and $320 million in contract authority. The difference between the anticipated program level of $700 million and the $575.5 million being made available now is expected to be provided upon enactment of 1980 appropriations.

This deferral is intended to maintain budgetary control on contract authority consistent with 1980 program plans. The amount deferred is not expected to be used in FY 1980.

Estimated Effect: This deferral action will have no programmatic effects.

Outlay Effect: There is no outlay effect of this deferral because the funds are not expected to be used if made available.

1/ This account was the subject of a similar deferral in FY 1979.

Deferral No: D80-22

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency Department of the Treasury	New budget authority (P.L. ______) $ ______
Bureau Office of Revenue Sharing	Other budgetary resources 79,547,717
Appropriation title & symbol State and Local Government Fiscal Assistance Trust Fund 1/ 20X8111	Total budgetary resources 79,547,717
	Amount to be deferred: Part of year $ 2,500,000 Entire year 77,047,717
OMB identification code: 20-8111-0-7-851	Legal authority (in addition to sec. 1013): ☒ Antideficiency Act ☒ Other P.L. 92-512, P.L. 94-488 (Sec.6)
Grant program ☒ Yes ☐ No	
Type of account or fund: ☐ Annual ☐ Multiple-year ______ (expiration date) ☒ No-year	Type of budget authority: ☒ Appropriation ☐ Contract authority ☐ Other ______

Justification: The Secretary of the Treasury must hold in reserve an amount to meet valid claims from State and local governments that past general revenue sharing payments to them were too small. Because the total amount appropriated for all governments is fixed, the alternative to such a reserve is recurring recomputations of entitlements of 39,170 governments for prior entitlement periods. Accordingly, the Office of Revenue Sharing withheld from obligation an amount equal to one-half of one percent of the amounts appropriated for each entitlement period through FY 1975. In addition, one-half of one percent of the amounts appropriated for general revenue sharing in the Economic Stimulus Appropriations Act, 1977 (P.L. 95-29) and the HUD-Independent Agencies Appropriation Act, 1978 (P.L. 95-119) was also withheld from obligation.

This cumulative unobligated reserve is available to the Secretary of the Treasury to satisfy legitimate claims against the Trust Fund for prior entitlement periods. After adjusting for such releases from the reserve, the deferred amount projected to carry over into FY 1980 is $79.5 million. The unobligated amount of $79.5 million retained in the Trust Fund will be further reduced whenever the Secretary determines the amount is adequate to meet foreseeable liabilities against the Trust Fund. The reduction will be made by paying the additional amount to recipients as part of a regular distribution.

Estimated Effect: This action will postpone distribution of the amount of the reserve until necessary adjustments and corrections have been identified. It will also avoid substantial confusion and complexities in the administration of the program.

Outlay Effect: This deferral has the effect of shifting $77 million in estimated outlays into FY 1981 ($39 million) and FY 1982 ($38 million).

1/ This account is currently the subject of another deferral and was the subject of a similar deferral during FY 1979.

Deferral No: D80-23

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of the Treasury	New budget authority (P.L. ____) $ ____
Bureau: Office of Revenue Sharing	Other budgetary resources 79,547,717
Appropriation title & symbol: State and Local Government Fiscal Assistance Trust Fund 1/ 20X8111	Total budgetary resources 79,547,717
	Amount to be deferred: Part of year $ 2,734,554 2/; Entire year ____
OMB identification code: 20-8111-0-7-851	Legal authority (in addition to sec. 1013): [X] Antideficiency Act
Grant program: [X] Yes [ ] No	[X] Other P.L. 92-512, Sections 121 & 123; P.L. 94-488
Type of account or fund: [ ] Annual; [ ] Multiple-year ____ (expiration date); [X] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ____

Justification: The State and Local Government Fiscal Assistance Trust Fund is the vehicle for disbursement of general revenue sharing funds. This deferral represents payments withheld from various governments involved in annexations or disincorporations and for reasons of noncompliance with the requirements of the State and Local Fiscal Assistance Act, as amended.

Estimated Effect: The release of these funds is contingent upon adherence by the various governments to the compliance regulations, and determinations as to which higher level of government is eligible to receive those funds withheld because of annexations and disincorporations.

Outlay Effect: There is no outlay effect of this deferral because the funds will be made available this fiscal year.

1/ This account is currently the subject of another deferral and was the subject of a similar deferral during FY 1979.
2/ Deferral of outlays only.

Deferral No: D80-24

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Department of the Treasury	New budget authority (P.L. ______) $ ______
Bureau: Bureau of the Mint	Other budgetary resources 5,729,583
Appropriation title & symbol: Construction of Mint Facilities 1/ 20X1617	Total budgetary resources 5,729,583
	Amount to be deferred: Part of year $3,229,583; Entire year ______
OMB identification code: 20-1617-0-1-803	Legal authority (*in addition to sec. 1013*): ☐ Antideficiency Act; ☐ Other ______
Grant program ☐ Yes ☒ No	
Type of account or fund: ☐ Annual; ☐ Multiple-year ______ (*expiration date*); ☒ No-year	Type of budget authority: ☒ Appropriation; ☐ Contract authority; ☐ Other ______

Justification: The Department of the Treasury is no longer seeking funding authority to construct a new mint at Denver. In lieu of a new mint, the Department is considering the acquisition of surplus federal buildings with the intention of rehabilitating them for metal processing and coinage operations, and also repairing and improving existing mint facilities. The results of a cost-analysis study conducted by the Bureau of the Mint are being evaluated to determine the most feasible approach. Construction funds totalling $3,229,583 are deferred pending this evaluation.

Estimated Effect: This action will delay the construction program pending the decisions made as a result of the cost-analysis study.

Outlay Effect: There is no outlay effect of this deferral.

1/ This account was the subject of a similar deferral in FY 1979.

Deferral No: D80-25

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Federal Emergency Management Agency	New budget authority (P.L. ______) $ ______
Bureau	Other budgetary resources $ 79,684
Appropriation title & symbol: Emergency Planning, Preparedness, and Mobilization 58X0200	Total budgetary resources 79,684
	Amount to be deferred: Part of year $ 79,684; Entire year ______
OMB identification code: 58-0200-0-1-054	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ______
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual; [ ] Multiple-year ______ (expiration date); [X] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ______

Justification: Funds were appropriated in 1964 and 1965, without fiscal year limitation, to assist State governments in developing programs for the management of their resources in time of emergency. The amount deferred is the residual of these funds that remain available. Current requirements for the funds will be reviewed by the new Federal Emergency Management Agency.

This deferral action is taken under the provisions of the Antideficiency Act (31 U.S.C. 665), which authorizes the establishment of reserves for contingencies.

Estimated Effects: This deferral has no significant programmatic or budgetary effect since there is no requirement for these funds at this time.

Outlay Effects: There is no outlay effect resulting from this deferral action since the funds could not be used if made available.

Deferral No: D80-26

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Foreign Claims Settlement Commission	New budget authority (P.L. ______) $ ______
Bureau	Other budgetary resources 1,900,000
Appropriation title & symbol: Payment of Vietnam Prisoner of War Claims 1/ 79X0104	Total budgetary resources 1,900,000
	Amount to be deferred: Part of year $1,800,000; Entire year ______
OMB identification code: 79-0104-0-1-153	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ______
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual; [ ] Multiple-year ______ (expiration date); [X] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ______

Justification: Public Law 91-289, approved June 24, 1970, authorizes the Foreign Claims Settlement Commission to adjudicate and certify for payment the claims of American military and civilian prisoners of war held during the Vietnam conflict, or their survivors. Before claims can be certified for payment by the Commission, the appropriate military services must determine the individual's POW status and, in the case of claims by the survivors of missing persons where evidence of captivity exists, it must also determine the date of death. Such determinations have been delayed pending the results of intense efforts to account for missing United States servicemen.

Appropriations were enacted in 1971, 1972 and 1973 for the Vietnam POW claims program to remain available until expended. Of the estimated $1,900,000 remaining available, $100,000 has been apportioned for 1980 to pay prisoner of war claims resulting from new determinations anticipated in 1980; $1,800,000 has been reserved. This deferral is necessary to achieve the most economical use of appropriations (31 U.S.C. 665(c)(1)) and to provide for contingencies after 1979 (31 U.S.C. 665(c)(2)).

Estimated Effects: No savings result from the deferral, since claims cannot be adjudicated or certified for payment by the Commission until final status determinations are made by the military services.

Outlay Effect: No effect on outlays results from this deferral action.

1/ This account was the subject of a similar deferral during FY 1979.

Deferral No: D80-27

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: International Communication Agency	New budget authority (P.L. ______) $ ______
Bureau	Other budgetary resources 20,770,832
Appropriation title & symbol: Acquisition & Construction of Radio Facilities 1/ 67X0204	Total budgetary resources 20,770,832
	Amount to be deferred: Part of year $ ______; Entire year 10,973,190
OMB identification code: 67-0204-0-1-154	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ______
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual; [ ] Multiple-year ______ (expiration date); [X] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ______

Justification: The United States International Communication Agency (ICA) was established by (1) the United States Information and Educational Exchange Act of 1948, as amended (22 U.S.C. 1431 et seq.); (2) the Mutual Educational and Cultural Exchange Act of 1961 (22 U.S.C. 2451 et seq.); (3) Executive Order No. 11034 of June 25, 1962, as amended, and (4) the Reorganization Plan No. 2 of 1977, to carry out international communication, cultural and educational exchange programs.

Funds for this program were carried forward from FY 1979, and were appropriated in the Departments of State, Justice, and Commerce, the Judiciary, and Related Agencies Appropriation Act, 1979 (P.L. 95-431, enacted October 10, 1978) and previous years, to remain available until expended, for the "Acquisition and Construction of Radio Facilities" account primarily to expand the transmitter capacity of the Voice of America's worldwide broadcasting system.

These funds, together with funds appropriated in FY 1978, would expand transmitter facilities in England, Liberia and the Philippines. Delays in these projects have been caused by lags in the procurement and scheduling process and by the need to arrange reprogrammings to finance increased estimated costs and exchange rate losses. Therefore, $10,973,190 is deferred for the Philippines and Liberia projects. These funds will be used in succeeding years.

This deferral action is taken in accordance with the Antideficiency Act (31 U.S.C. 665).

Estimated Effect: There are no programmatic or budgetary effects resulting from this deferral action.

Outlay Effect: There is no outlay effect of this deferral, because the funds could not be used if made available.

1/ This account was the subject of a similar deferral during FY 1979.

Deferral No: D80-28

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: National Alcohol Fuels Commission	New budget authority (P.L. ____) $ ____
Bureau	Other budgetary resources 1,350,000
Appropriation title & symbol: Salaries and expenses 1/ 48X1700	Total budgetary resources 1,350,000
	Amount to be deferred: Part of year $ —; Entire year 250,000
OMB identification code: 48-1700-0-1-271	Legal authority (in addition to sec. 1013): ☒ Antideficiency Act ☐ Other ____
Grant program ☐ Yes ☒ No	
Type of account or fund: ☐ Annual ☐ Multiple-year ____ (expiration date) ☒ No-year	Type of budget authority: ☒ Appropriation ☐ Contract authority ☐ Other ____

Justification: Authorized by P.L. 95-599, the Federal-Aid Highway Act of 1978, the National Alcohol Fuels Commission is undertaking a thorough investigation of the long and short-term potential of alcohol fuels from various sources as a way to meet the nation's energy needs. The Commission will recommend policies and assess the associated costs and benefits of these policies.

The Supplemental Appropriations Act, 1979 (P.L. 96-38) provided $1.5 million to establish the Commission and begin its operations. Of this amount, $150,000 was obligated in FY 1979, and only $1.1 million is necessary for obligation in FY 1980 to operate the Commission. Therefore, $250,000 is deferred for the remainder of this fiscal year.

This deferral action is taken in accordance with the Antideficiency Act (31 U.S.C. 665).

Estimated Effects: This deferral will have no budgetary or programmatic impact.

Outlay Effects: There is no outlay effect resulting from this deferral.

1/ This account was the subject of a similar deferral during FY 1979.

Deferral No: D80-29

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: National Commission on Social Security	New budget authority (P.L. ____) $ ____
Bureau	Other budgetary resources 1,943,000
Appropriation title & symbol: Salaries and Expenses 1/ 489/11600	Total budgetary resources 1,943,000
	Amount to be deferred: Part of year $ ____; Entire year 250,000
OMB identification code: 48-1600-0-1-601	Legal authority (in addition to sec. 1013): [X] Antideficiency Act; [ ] Other ____
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual; [X] Multiple-year September 30, 1981 (expiration date); [ ] No-year	Type of budget authority: [X] Appropriation; [ ] Contract authority; [ ] Other ____

Justification: The National Commission on Social Security, a temporary commission, was established by P.L. 95-216 to study, investigate, and review the cash benefits and health insurance programs authorized by Titles II and XVIII of the Social Security Act. Initially, $500,000 was provided in P.L. 95-480 for initial costs, with an additional $2.0 million provided in the Supplemental Appropriations Act, 1979 (P.L. 96-38) for continued operations.

Funds totalling $250,000 are deferred to assure prudent financial management. None of these funds could be used effectively or efficiently during FY 1980.

This deferral action is taken in accordance with the Antideficiency Act (31 U.S.C. 665), and is in accord with congressional intent to provide funding for the full two-year life of the Commission.

Estimated Effect: This deferral will have no budgetary or programmatic impact.

Outlay Effect: There is no outlay effect resulting from this deferral.

1/ This account was the subject of a similar deferral during FY 1979.

Deferral No: D80-30

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency Navajo and Hopi Indian Relocation Commission	New budget authority (P.L. ____) $ -
Bureau	Other budgetary resources 15,240,000
Appropriation title & symbol Salaries and Expenses 1/ 48X1100	Total budgetary resources 15,240,000
	Amount to be deferred: Part of year $ ____ Entire year 5,300,000
OMB identification code: 48-1100-0-1-806	Legal authority (in addition to sec. 1013): [X] Antideficiency Act [ ] Other ____
Grant program [ ] Yes [X] No	
Type of account or fund: [ ] Annual [ ] Multiple-year ____ (expiration date) [X] No-year	Type of budget authority: [X] Appropriation [ ] Contract authority [ ] Other ____

Justification: The Navajo and Hopi Indian Relocation Commission estimates that there will be approximately $15,240,000 available for assistance and relocation payment purposes carried forward into FY 1980. Based on current relocation estimates, only $9,940,000 will be needed during FY 1980 to carry out the work of the Commission. Additional funds will be made available if needed.

Estimated Effect: There are no programmatic or budgetary effects resulting from this deferral.

Outlay Effect: No effect on outlays results from this deferral action.

1/ This account was the subject of a similar deferral during FY 1979.

Deferral No: D80-31

DEFERRAL OF BUDGET AUTHORITY
Report Pursuant to Section 1013 of P.L. 93-344

Agency: Tennessee Valley Authority	New budget authority (P.L. ____) $ ----
Bureau	Other budgetary resources 32,287,000
Appropriation title & symbol: Payment to the Tennessee Valley Authority Fund 1/ 64X4110	Total budgetary resources 32,287,000
	Amount to be deferred: Part of year $ 17,000,000; Entire year ____
OMB identification code: 64-4110-0-3-999	Legal authority (in addition to sec. 1013): ☐ Antideficiency Act ☐ Other ____
Grant program ☐ Yes ☒ No	
Type of account or fund: ☐ Annual ☐ Multiple-year ____ (expiration date) ☒ No-year	Type of budget authority: ☒ Appropriation ☐ Contract authority ☐ Other ____

Justification: The Fish and Wildlife Service has issued a biological opinion that the completion of the Columbia Dam project as presently planned would jeopardize the continued existence of three endangered mussel species--the birdwing pearly mussel and two others. Accordingly, under existing law and in light of the U.S. Supreme Court's decision in the Tellico case, (Tennessee Valley Authority v. Hill, 46 U.S.L.W. 4673 (U.S. June 15, 1978)), it would be unlawful to complete the project as originally designed without: (1) the delisting of the affected species, (2) an exemption under the 1978 Endangered Species Act Amendments, or (3) a favorable modification in the Fish and Wildlife Service's biological opinion. The Fish and Wildlife Service is now reconsidering this opinion on the basis of a resurvey conducted by TVA at its request. A new opinion based on the resurvey is expected within 90 days.

In addition, completion of the project as planned is dependent upon issuance by the Corps of Engineers of a permit under Section 404 of the Clean Water Act for placement of fill material. The Section 404 permit cannot be issued without a certification by the State of Tennessee under Section 401 of the Clean Water Act that discharges authorized by the permit will not cause violation of the State water quality standards. The Corps is now awaiting the certification by the State and the resolution of Endangered Species Act issues. The certification (applied for by TVA over a year ago) is being delayed by an administrative appeal filed by the environmental groups that oppose the project.

As a result of these legal impediments to completion of the project, TVA has confined its activities at the Columbia dam site during fiscal year 1979 to include highway and road construction, land buying related to low-reservoir pool and road construction, and miscellaneous minor work. TVA must continue to curtail its construction activities at the Columbia site until solutions to the problems described above are found. Therefore, based upon most recent estimates, $17,000,000 is deferred pending resolution of these issues.

1/ This account was the subject of a similar deferral in FY 1979.

D80-31

Estimated Effect: The construction of various portions of the Columbia Dam will be delayed pending resolution of the legal and environmental problems.

Outlay Effect: This deferral, by itself, has no outlay effect. However, the legal matters delaying this project, which have brought about the deferral, have the effect of postponing use of the deferred funds until those matters are resolved.

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federal register

Friday
October 5, 1979

Part X

Department of Energy

Department of the Treasury

Hearings and Request for Public Comment on Enforcement of Oil Import Quota

DEPARTMENT OF ENERGY

DEPARTMENT OF THE TREASURY

[Docket No. ERA-R-79-44]

Hearings and Request for Public Comment on Enforcement of Oil Import Quota

AGENCY: Departments of Energy and Treasury.

ACTION: Notice of hearings and request for public comment.

SUMMARY: The Department of Energy (DOE) and the Department of the Treasury are seeking public comment to assist them in making recommendations to the President concerning the enforcement of the oil import quota announced by the President on July 15, 1979. This Notice sets forth a description of three alternative approaches to implementing the quota. The public is invited to submit additional alternatives, or combinations thereof, which will receive consideration as long as they are capable of achieving the goals set forth by the President.

DATES: Written comments are due by November 9, 1979. Hearings will be held in San Francisco on October 29, 1979; in Dallas on October 31, 1979; in Chicago on November 2, 1979; in Boston on November 6, 1979; and in Washington, D.C. on November 7, 1979. All hearings will begin at 9:30 a.m. local time. Requests to speak at the regional hearings must be received by October 22, 1979. Requests to speak at the Washington, D.C. hearing must be received by October 24, 1979.

ADDRESSES: A. HEARING LOCATIONS:

1. Boston—John W. McCormick, Post Office and Court House Bldg., 2nd Floor Conference Room No. 208, No. 5 Post Office Square, Boston, Massachusetts.
2. San Francisco—Holiday Inn, Gold Rush Room No. B, 1500 Van Ness Avenue, San Francisco, California.
3. Dallas—Dallas Dunfey Hotel, Texas One Room, 3800 West Northwest Highway, Dallas, Texas.
4. Chicago—E. M. Dirksen Federal Bldg., Room 204A, 219 South Dearborn, Chicago, Illinois.
5. Washington, D.C.—James Forrestal Building, Auditorium, Room GE-086, 1000 Independence Avenue, S.W., Washington, D.C.

B. REQUESTS TO SPEAK:

Requests to speak should be addressed to the following offices:

1. Boston Hearing: Department of Energy, ATTN: Kathy Healy, Room 700, 150 Causeway Street, Boston, MA 02114.
2. San Francisco Hearing: Department of Energy, ATTN: Terry Osborne, 3rd Floor, 111 Pine Street, San Francisco, CA 94111.
3. Dallas Hearing: Department of Energy, ATTN: Mac L. Lacefield, 2626 West Mockingbird Lane, P.O. Box 35228, Dallas, TX 75235.
4. Chicago Hearing: Department of Energy, ATTN: Lou Brownlee, 175 West Jackson Boulevard, Chicago, IL 60604.
5. Washington, D.C. Hearing: ERA Docket No. ERA-R-79-44, Department of Energy, Room 2312, 2000 M Street, N.W., Washington, D.C. 20461.

C. WRITTEN COMMENTS:

All written comments should be addressed to: ERA Docket No. ERA-R-79-44, Department of Energy, Room 2312, 2000 M Street, N.W., Washington, D.C. 20461.

FOR FURTHER INFORMATION CONTACT:

Robert C. Gillette (Office of Public Hearings Management), Economic Regulatory Administration, Room 2312, 2000 M Street, N.W., Washington, D.C. 20461, (202) 254-5201.

Robert D. R. de Sugny (Office of General Counsel), Department of Energy, Room 5116, 12th and Pennsylvania Avenue NW., Washington, D.C. 20461, (202) 633-9380.

James Harkins, III. (Office of Oil Imports), Department of Energy, Room 4210, 2000 M Street NW., Washington, D.C. 20461, (202) 254-8620.

Josette L. Maxwell (Regulations and Emergency Planning), Economic Regulatory Administration, Room 8202L, 2000 M Street, NW., Washington, D.C. 20461, (202) 632-5133.

Steve McGregor (Policy and Evaluation), Department of Energy, Room 7H063, James Forrestal Building, 1000 Independence Avenue SW., Washington, D.C. 20585, (202) 252-5626.

Ed Valade (Public Affairs), Department of Energy, Room 8E082, James Forrestal Building, 1000 Independence Avenue SW., Washington, D.C. 20585, (202) 252-5806.

SUPPLEMENTAL INFORMATION:

I. Background

In his address to the nation on July 15, 1979, President Carter announced quotas on imports of foreign oil in order to limit those imports to a level which would be below the amount imported in 1977. The President noted that in the past two decades, the U.S. has been reduced from a position of energy independence to the point where almost one-half of our oil is imported and that "[t]his intolerable dependence on foreign oil threatens our economic independence and the very security of our nation." This action followed the Tokyo Economic Summit Conference held in June, 1979, at which the United States and the other nations attending the Summit agreed that each country would take action to limit imports of oil to agreed upon levels.

The Secretaries of Energy and Treasury have been directed to develop recommendations on a mechanism for enforcement of the quota. This notice outlines three possible approaches to implementing the quota and the comments submitted by the public in response will be considered in formulating the final recommendations. It should be noted that the quota enforcement mechanism selected may not necessarily resemble one of the three approaches outlined here if further study and public comments indicate the need for an additional alternative or a combination of various alternatives.

The President's authority to establish a quota on oil imports is based on Section 232(b) of the Trade Expansion Act of 1962, as amended, which provides that upon a finding by the Secretary of the Treasury that a commodity is entering the country "in such quantities or under such circumstances as to threaten to impair the national security", the President may "take such action, and for such time, as he deems necessary to adjust the imports of [the commodity] . . . ." Pursuant to this authority (and the authority of a predecessor statute), investigations of imports of petroleum and petroleum products were conducted in 1959, 1975 and most recently in March, 1979. In each case, it was found that imports of petroleum and petroleum products were entering the country "in such quantities and under such circumstances as to threaten to impair the national security." Following the initial finding in 1959, President Eisenhower issued Presidential Proclamation 3279 which established the Mandatory Oil Import Program (MOIP), a quota system for controlling imports of petroleum and petroleum products. In 1973, the MOIP was amended to eliminate quantitative limits on imports and substitute a system of licenses subject to the payment of fees. The fees, which were $0.21 per barrel for crude oil and $0.63 per barrel for petroleum products, were suspended effective April 1, 1979 as a result of the world shortages of petroleum which followed the near cessation of Iranian exports. At the current time there are no restrictions on the importation of oil into the United States other than the requirement that one must first obtain a license from the Office of Oil Imports of DOE.

Section II of this notice describes the three alternative means of implementing the quota. General issues are discussed in Section III and specific questions with respect to the various quota options are raised in Section IV of this notice.

II. Alternative Quota Systems

1. *Alternative No. 1: Auction System.* Under an auction system, a fixed quantity of oil import rights would be distributed by periodic sale to the highest bidders. Interested parties would submit to the designated agency an offer stating the prices they would pay for various quantities of import rights (*i.e.* multiple bids would be accepted). Bids would be filled down to the quantity which exhausts the quota. The price paid by successful bidders would be the price bid. Rights would be transferable, assuring that those who subscribed in excess of their needs could dispose of their excess rights, while at the same time providing an opportunity for those desiring additional rights to purchase them.

Auctions would occur on a periodic basis, possibly quarterly, with a seasonally weighted percentage of the annual quota available at each sale. Licenses would be valid for a specific four month period. These periods would overlap to provide continuity in the availability of licenses, while lessening the potential for market manipulation.

Bidders would be required to post either 50% of the dollar amount bid in cash or post a bond in the full amount at the time the bid is submitted. Bonded licenses would not be transferable unless converted to a pre-paid license or the purchaser posted his own bond. Successful bidders who had made a partial cash payment would have to remit the balance prior to a license being issued and would forfeit the payment, and be liable for the balance, if they failed to take delivery of the license. Persons posting bonds who failed to take delivery of the license would forfeit the bonds. Persons posting bonds would be required to submit monthly remittances for actual imports, with the balance due on the expiration date of the license. No refunds would be provided for unused portions of licenses.

2. *Alternative No. 2: License Fee.* Under the license fee system, imports would be limited by imposing a sufficient fee on imports to reduce demand to the quota level. DOE would calculate the appropriate per barrel fee which would be necessary to reduce imports to the quota level.

The fee system would operate in a manner similar to the MOIP, except that the program would be simplified. If requests for import licenses exceeded the quota because of unexpected demand, the fee would be increased in subsequent periods. If a fee system were adopted, there would probably be one fee level for all petroleum imports and there would be no restriction on eligibility or transferability. Licenses would be sold on a periodic basis, possibly quarterly, and they would be valid for a specific four month period, the periods overlapping. Bonds could be posted in lieu of prepayment of fees in a manner similar to the MOIP except that persons posting bonds would be liable for the unused balance of any expired licenses. Similarly no refunds would be available for pre-paid licenses which were not fully utilized.

3. *Alternative No. 3: No Charge Allocation.* Under the no charge allocation system, imports would be limited by distributing, without charge, licenses which would confer the right to import a fixed quantity of crude oil and finished or unfinished products. If historical precedents are followed, import licenses for crude oil and unfinished oils would be distributed among all those with capacity to process such petroleum. The volume of import rights conferred could be determined by the refiner's crude runs to stills or by certified crude distilling capacity. Import licenses would be transferable which would enable those refiners who are more dependent on foreign feedstocks to acquire import rights from those refiners less able to use them.

Under the MOIP, rights to import some finished products were allocated to historic importers, such as deepwater terminal operators, marketers, and large volume consumers, and they could be distributed under the quota on a similar basis. Finished products would be allocated on an annually adjusted historical basis and the licenses would be transferable.

If all licenses are made freely transferable, new entrants will be able to enter the market, but possibly at a substantial competitive disadvantage compared to existing allocation holders.

III. General Issues

1. *Geographic and Product Coverage.* The quota established by the President at the Tokyo Economic Summit Conference and in his national energy address, assumed a certain geographic scope and commodity coverage. However, no final determinations have been made and comments are therefore solicited on these questions.

Under the assumptions utilized in setting the quota, the geographic scope of the program would include the fifty states and the District of Columbia. U.S. territories and foreign trade zones would not be subject to the quota. Thus, petroleum imported into those areas from foreign sources would not be counted but products shipped to the U.S. from those areas would be subject to the established level. While this approach appears to be appropriate, its applicability, especially with respect to Puerto Rico, continues to be evaluated.

Petroleum imports encompassed by the quota would include some items formerly exempt from import controls under the MOIP. Petroleum imports under the quota would include crude oil, unfinished oils and finished products, as defined in Section II of Proclamation 3279, as amended. Those definitions would be retained in the new system; however, the exclusion for imports of asphalt, ethane, propane and butanes contained in Section 2(d) of the Proclamation would be eliminated as would the limitation on specialized petroleum products that excluded those products subject to a duty of more than one cent per pound as of January 1, 1973, under the Tariff Schedules of the United States. The elimination of this latter limitation would mean, for example, that all imports of petroleum based lubricants would be subject to the quotas. In addition to the preceding products, imports of petroleum coke and paraffinic waxes would be subject to the quota.

2. *International Exchanges.* Because the quota level is a function of *net* imports, a person will not affect the quota limit if he exports oil from the United States as part of an exchange with persons in foreign countries. We believe that persons importing oil as a result of exchange agreements approved under U.S. Export Control regulations should be allowed to obtain a license without cost. A possible approach might provide that a person would be able to obtain licenses upon a determination that the proposed exchange was consistent with the purposes of the program and that the oil which will be exported will not be taken from an oil deficient region.

3. *Tariff.* Presidential Proclamation No. 4655 temporarily suspended both the license fees under the MOIP and tariffs on imports of petroleum and petroleum products as of April 1, 1979. Prior to that time, payment of tariffs, which vary depending on gravity or end use, was credited against license fee obligations. The fee therefore provided a uniform level of protection.

Under some of the quota systems, this would not be possible and therefore the tariffs would provide a level of protection for domestic refining capacity which, in some cases such as gasoline imports, will be almost equal to that afforded by the MOIP. Elimination of the tariff refund has been assumed and comments should reflect the existence of present tariff levels.

4. *Petroleum Product and Petrochemical Exports.* The quota level will reflect net imports, *i.e.* total import volumes minus the volume exported. Exports for the initial quota period will be estimated by DOE. Once estimated, the question arises as to whether the additional quantities of imports which are made available by exports should be used to generally increase the volume of import rights distributed or whether they should be used to provide a refund or credit to those persons who actually exported.

IV. Specific Comments Requested

In addition to the issues which have been raised in the preceding discussion, we would appreciate comment on the general workability, relative economic impact, and the ability of each alternative to meet the quota, as well as comment on the following questions. To facilitate processing of comments, we would appreciate identification of your comment by reference to the questions as numbered below.

1. *With Respect to an Auction System.* (a) One concern often expressed with respect to the auction system is that persons or companies with substantial financial resources could bid for such quantities and at such prices so as to exclude others from the market. Would a noncompetitive bid provision (which would allow parties to enter a request for a quantity of import rights for which they would pay the minimum successful bid price of the auction for that quantity plus a minimal surcharge) be sufficient to avoid this problem? Do we need a provision such as described above to guarantee access to import rights? If so, should there be a limit on the quantity obtained by any one purchaser? Could this procedure, thus, allow a few participants to set the price of import rights? Is there an alternate procedure which would achieve the same end?

(b) Since the value of import rights can fluctuate, is there a need for any restrictions on bids in order to prevent speculative bidding? In this connection, is there a need for a minimum bid price and, if so, what price level woud suffice? Should we establish a quantitative limtation, *i.e.* a maximum amount of import rights which could be purchased by any one person, based on a percentage of historic import levels or some other method?

(c) Should we restrict eligibility to participate in an auction? If so, what should be the criteria for selection of eligible participants? If restrictions on eligibility were adopted, should purchasers in the secondary market be required to meet these same eligibility criteria?

(d) Licenses would only be valid for a period of four months under the proposal. Is this period sufficient to permit the planning of import purchases or should bids for future time periods be permitted? If bids for future periods are allowed, what percentage of the quantities allotted to future auction periods should be made available and over what time period should they be valid? How far in advance of the quota period should the auction take place?

(e) Are there factors which would make it desirable to establish upper limits on the prices which could be bid?

(f) What is an appropriate lot size (number of barrels) that each license should represent?

(g) At the begining of the MOIP, allocation of licenses for crude oil among refiners was historically based. This system was gradually phased out over the life of the program, and replaced with an allocation system based on refinery input and biased toward smaller refineries. Is the noncompetitive bid provision adequate or necessary to accomplish this purpose? Would such a provision result in the construction of inefficient refineries?

2. *Questions with respect to the License Fee System.* (a) Should the fee be established on a one-time basis or should it be adjusted periodically based on whether quota targets are being met? If the fee is adjusted periodically, how often should it be adjusted?

(b) Should there be any restrictions on eligibility or transferability?

(c) One difficulty with respect to a license fee system is calculating the appropriate fee which will reduce demand to the quota level. As an alternative to increasing the fee, would it be feasible to combine a license fee system with a standby system for distributing import rights which would be triggered if imports began to approach the quota ceiling?

3. *Questions With Respect to No Charge Allocation System.* (a) Although the system as described states that allocations could be granted to refiners and importers, import rights could be distributed to additional, or even entirely different, classes of recipients. On what basis should the allocations be distributed and what effect will it have on the petroleum market?

(b) Would an exception process be necessary in order to ensure that new entrants have access to import rights? As an alternative, would equitable access to import rights be provided by requiring new entrants initially to acquire such rights in a secondary market but then retroactively to allocate, in a subsequent period, an amount equal to some percentage of the new entrant's initial imports?

(c) At the beginning of the MOIP, allocation of tickets for crude oil among refiners was based on historical minimums. This system was gradually phased out over the life of the program, and replaced with an allocation system based on refinery input and biased toward smaller refineries. The proposed system is not biased on the basis of size. Is there a need for such a bias and if so, how can it be structured to minimize the construction of inefficient refineries?

(d) The proposed system would allocate import rights to importers of finished products on a historical basis. How should a base period for product imports be chosen?

(e) Under the no charge allocation system, licenses could be made transferable. Would this increase the danger of unwarranted speculation or market manipulation and if so, could this danger be avoided by limitations on the quantity of licenses each person can hold? Should license holders be required to use the oil themselves?

(f) What complexities or problems are caused by the combination of this system with the current mandatory allocation and price controls currently scheduled to expire in October of 1981?

4. *The following questions are applicable to more than one of the alternatives.* (a) A major question is whether there should be one overall quota for both crude and products or whether there should be separate quotas. If it were determined that the quota program should contain an element of protection for domestic refiners, or if it were determined that regional impacts should be taken into account through the quota mechanism, one quota could be established for crude and unfinished oil, and another for finished products. Finished products, in turn, could be separated into the categories of residual fuel oil and all other petroleum products. Would these categories suffice?

What would be the regional and industry impacts of a single quota? Does this vary depending on the alternative? Would separating the overall quota into sub-categories of crude and unfinished oils, residual fuel oil, and all other petroleum products reduce flexibility and lead to the inefficient distribution of imports, and complicate long-term planning? One way of restoring some flexibility would be to allow crude oil licenses to also be used for residual fuel oil imports and to allow product licenses to be used for both other categories but this would still not provide for circumstances where, for example, there was an emergency need for a certain type of product import at a time when that quota was exhausted and the others were not. Would the possibility of altering the relative amounts in each of the quota categories during the middle of a quota period (which could have significant impact on the value of the import rights) induce excessive uncertainty in the planning of ticket purchases or could clear standards for such emergency adjustments be devised so that persons holding the rights could anticipate any change? For example, under the auction system, standards for the triggering of an adjustment could be based on the difference in relative value of the different types of quota licenses. When the triggering price differential was reached, any unauctioned licenses of other types could be released through a supplemental auction. If all licenses have already been auctioned, then the system could either allow the convertibility of a certain percentage of the less valuable types of licenses or the quota for the succeeding period of the less valuable types of licenses could be reduced by the amount of additional licenses which were needed to increase imports in the "emergency" category. Would such a system restore the flexibility lost by dividing the overall quota? Would controls be necessary to regulate the substitution of licenses, and if so, what controls would be appropriate?

(b) Can issues of regional impact and impact on the domestic refining industry be dealt with under one or another of the systems presented?

(c) What are the international and domestic impacts of including natural gas liquids within the quota?

(d) Under the MOIP, there was a provision which, in effect, subsidized construction of new, expanded, or reactivated refinery capacity for a period of five years following activation. Considering that the quota program is designed to reduce domestic petroleum consumption, which in turn would reduce the need for refinery capacity, is there still a need for this type of benefit? If so, how should it be structured and would it be more appropriate to accomplish such a purpose through legislation?

(e) If oil import rights once acquired are freely transferable, a secondary market will develop at prices reflecting changing economic conditions. Would the nature of price setting in such secondary markets create problems which would require imposition of government controls, and if so, what controls would be appropriate?

(f) What problems will arise in the transition from the existing MOIP to the new quota system?

(g) Small quantities of certain imports were exempted under the MOIP and the implementing regulations. Would similar provisions suffice under the quota system?

(h) With respect to exports, would providing a credit for exports foster import dependency within the exporting sector of those industries receiving such benefits, especially if credits were extended to imported crude and unfinished oil and not to domestic oil? Credits might also require an administratively complex system in order to determine the actual value of the import right at the time the crude or unfinished oil was secured for processing into the export. While this could be avoided by relating the value of the credit to the time of export, would such an approach result in refunds greater or smaller than warranted and, as a consequence, affect the marketing of exports? Should any credit or refund system which might be adopted extend to products other than finished petroleum products, and if so, on what basis can a distinction be made between such exports and other energy intensive exports?

V. Public Comment and Hearing Procedures

A. *Written Comments.* You are invited to participate in this proceeding by submitting data, views or arguments with respect to the general and specific issues and questions set forth in this Notice. Comments should be identified on the outside envelope and on documents submitted with the designation "Import Quota Systems", Docket No. ERA-R-79-44 and submitted by the date indicated in the "Dates" section of this Notice and to the address indicated in the "Address" section. Ten copies should be submitted. Any information or data submitted which you consider to be confidential must be so identified and submitted in writing, one copy only. We reserve the right to determine the confidential status of such information or data and to treat it according to our determination.

Because we anticipate a large response, we would appreciate it if you would initially identify each comment by the specific section of the Notice to which it pertains or to the number of the appropriate question if the comment is in response to Section IV. All comments received will be available for public inspection in the DOE Freedom of Information Office, Room GA-152, James Forrestal Building, 1000 Independence Avenue, S.W., Washington, D.C., between the hours of 8:00 a.m. and 4:30 p.m., Monday through Friday.

B. *Public Hearings.* 1. *Procedure for Requesting Participation.* The times and places for the hearings are indicated in the preamble. If necessary to present all testimony, hearings will be continued at 9:30 a.m. on the next business day following the first day of the hearing.

Requests for an opportunity to make an oral presentation at the hearings should be addressed as noted in the preamble and received no later than October 22, 1979 for the regional hearings and October 24, 1979 for the Washington, D.C. hearing. The requests should contain a phone number where you may be contacted through the day before the hearing.

We will notify each person selected to be heard before 4:30 p.m., October 26, 1979 for the regional hearings and October 31, 1979 for the Washington, D.C. hearing. Persons scheduled to speak at the hearings must bring 100 copies of their statement to the regional hearings on the date of the hearing and to the Office of Public Hearings Management, Room 2313, 2000 M Street, N.W., Washington, D.C. by 4:30 p.m., November 6, 1979, for the Washington hearing.

2. *Conduct of the Hearing.* We reserve the right to select the persons to be heard at the hearings, to schedule their respective presentations, and to establish the procedures governing the conduct of the hearings. The length of each presentation may be limited, based on the number of persons requesting to be heard.

A DOE official will be designated to preside at the hearings, which will not be judicial in nature. Questions may be asked only by those conducting the hearing. At the conclusion of all initial oral statements, each person who has made an oral statement will be given the opportunity to make a rebuttal statement. The rebuttal statements will be given in the order in which the initial statements were made and will be subject to time limitations.

You may submit questions to be asked by the presiding officer of any person making a statement at the hearings. Such questions should be submitted to the address indicated above for requests to speak, for the location concerned, before 4:30 p.m. on the day prior to the hearing. If at the hearing you decide that you would like to ask a question of a witness, you may submit the question, in writing, to the presiding officer. In either case, the presiding officer will determine whether the time limitations permit it to be presented for a response.

Any further procedural rules needed for the proper conduct of a hearing will be announced by the presiding officer.

Transcripts of the hearings will be made, and the entire record of the hearings, including the transcripts, will be retained by the DOE and made available for inspection at the Freedom of Information Office, Room GA-152, James Forrestal Building, 1000 Independence Avenue, S.W., Washington, D.C., between the hours of 8 a.m. and 4:30 p.m., Monday through Friday. Any person may purchase a copy of the transcript from the reporter.

In the event that it becomes necessary for us to cancel a hearing, we will make every effort to publish advance notice in the Federal Register of such cancellation. Moreover, we will give actual notice to all persons scheduled to testify at the hearings. However, it is not possible to give actual notice of cancellations or changes to persons not identified to us as participants. Accordingly, persons desiring to attend a hearing are advised to contact DOE on the last working day preceding the date of the hearing to confirm that it will be held as scheduled.

Issued in Washington, D.C., October 3, 1979.

Charles W. Duncan, Jr.,
Secretary of Energy.

Robert Carswell,
Acting Secretary of the Treasury.

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